An Coimisiún um Rialáil Fóntais
Commission for Regulation of Utilities

Price Review Six (PR6)

Transmission Revenue for 2026 - 2030

Final Determination

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The Exchange, Belgard Square North, Tallaght, Dublin 24, Ireland
T +353 1 4000 800 | F +353 1 4000 850 | www.cru.ie

CRU Strategic Plan 2025-27

Vision, Purpose, and Values



OUR VISION:

Resilient, efficient, sustainable, and safe energy and water services for Ireland.



OUR PURPOSE:

We actively serve the public interest by regulating the provision of energy and water to Irish homes and businesses, while supporting the transformation to net zero.



OUR VALUES:

• Integrity • Professionalism • Openness • Accountability

Executive Summary

Purpose of this document

The Commission for Regulation of Utilities (CRU) is responsible for the economic regulation of the electricity network companies in Ireland. To do this, the CRU sets price reviews which limit the revenues that the network companies can recover from electricity customers. Price reviews are set every 5 years and the upcoming Price Review Six (PR6) will cover the period, 1 January 2026 to 31 December 2030.

Having considered all responses received on the CRU's PR6 Draft Determination, this document sets out the CRU's Final Determination on the allowed expenditure and the associated allowed revenues for EirGrid and ESB Networks, licensed by the CRU as the Transmission System Operator (TSO) and Transmission Asset Owner (TAO).

Background and summary of Final Determination updates

The electricity transmission system is responsible for delivering power from generation sources to local distribution networks. It consists of an interconnected grid of substations, transformers, and transmission lines that ensure electricity reaches homes, businesses, and industries efficiently and reliably. A well-functioning transmission system is crucial for maintaining grid stability, enabling energy security, and supporting the transition to a decarbonised electricity system by integrating renewable energy at scale.

For PR6, the CRU's Strategy Paper set out the strategic approach, objectives and outcomes that should be delivered by ESB Networks and EirGrid (together the "network companies") including the ambition to build on the progress made through the previous price review period, Price Review 5 (PR5).[1]

It is important to recognise that PR5 represented a significant change for the regulatory framework in Ireland, with increased importance placed on achieving outcomes and objectives, particularly around decarbonisation, relative to previous price reviews. Overall, this has driven positive, but mixed, results for customers, with evidence that network companies have helped progress delivery of some decarbonisation and net zero targets but have fallen short in other areas such as resolving local security of supply issues.

[1] CRU202427 – Price Review Six Strategy Paper

Another positive development in PR5, was the introduction of the Agile Investment Framework (AIF), comprising of a series of mechanisms to allow access to additional revenues during the price review period, thus allowing for a more flexible approach to network investments.

In the Price Review Six Regulatory Framework Paper (CRU2025197), the CRU sets out in detail the PR6 regulatory framework including the approach to cost recovery and managing uncertainty, performance incentives (PIs), and reporting, monitoring and governance arrangements. For the purpose of this document, which sets out the allowed expenditure and revenues, it is important to understand the changes to the AIF, which is now referred to as the Agile Investment and Monitoring Framework (AIMF). The PR6 regulatory framework includes a suite of mechanisms to deal with the inevitable changes in priorities and circumstances (and hence costs) that will arise over the period.

Ireland's electricity system is undergoing rapid change, which is driving a significant step change in the level of investment required in the networks, while also increasing the overall level of uncertainty around the timings, pathways and delivery of different projects and investment programmes. The CRU expects that network companies' allowed expenditure and associated revenues will need to adjust during the price review period to reflect changes in scope and or investment pathway. As noted above, the AIF was introduced in PR5 to provide agility and flexibility, but in practice network companies did not have confidence that it would sufficiently allow for flexing up/down of expenditure and revenues and it struggled to deal with the degree of change that actually occurred during PR5. For example, it was not designed to manage the step-changes associated with Climate Action Plan (CAP) 2021 and the security of supply challenges that arose mid-period.

The new AIMF for PR6, building on the AIF, is expected to perform a fundamental role as an agile, streamlined, and permissive framework that provides a pathway for network companies to flexibly access additional expenditure and associated revenues during the period, where the submission documentation is complete and is structured to place accountability for approvals within the network company's senior governance framework.

To give confidence to network companies that additional revenues will be available when required, and to manage the level of risk that customers should bear, the CRU is providing a clear *ex-ante* commitment on the envelope of revenue allowances that may ultimately be required to deliver on the PR6 outcomes and objectives.

As set out in this document, the CRU's decision is to provide:

- *ex-ante* baseline operational expenditure (opex) and capital expenditure (capex) allowances – as discussed above, part of which are ring-fenced to particular programmes as part of delivery obligations (DOs); and

- opex and capex allowances which the CRU confirms are accessible to companies through the AIMF (also referred to as 'high case' allowances) to meet the electricity network needs.

The approved baseline allowances are forecast business and PR6 project / programme costs, for which the CRU currently has higher confidence in the need, additionality, scope and cost based on the technical reports provided by the CRU's advisors, CEPA and GHD (CRU2025203, CRU2025204 and CRU2025206). The approved envelope (high case) allowances are expenditure that the CRU confirms may be needed and is approving as accessible during PR6.

Network companies will be expected to seek approval through the AIMF's targeted (scheme / category specific) reopeners and volume driver mechanisms for additional allowances in the high case to be released into allowed revenues during PR6. As stated previously, reopener submission processes, including the associated submission requirements, are designed to largely align with the companies' internal governance processes. This is to ensure that the regulatory burden on the companies is minimised, and the CRU's assessment is rapid and permissive in nature, avoiding regulatory blockers to investment or progressing delivery (refer to the Price Review Six Regulatory Framework Paper (CRU2025197) for more information).

The CRU's evolution of the regulatory framework, set out as part of this Final Determination, improves funding flexibility and introduces clearer accountability for delivery. It reflects the CRU's commitment to enable delivery of the infrastructure required to meet the evolving needs of the transmission system, while safeguarding the interests of current and future consumers.

Draft Determination Responses

The CRU received forty-four [44] responses to the Draft Determination from a wide cohort of stakeholders. Over 60% of comments focussed on capex, the regulatory framework and bill impacts. The key themes of the responses include:

- Scale and strategic direction of investment;
- Delivery risk and organisational capacity;
- Financial framework and affordability;
- Flexibility, technology and Innovation; and
- Electrification, connections and network planning/efficiency.

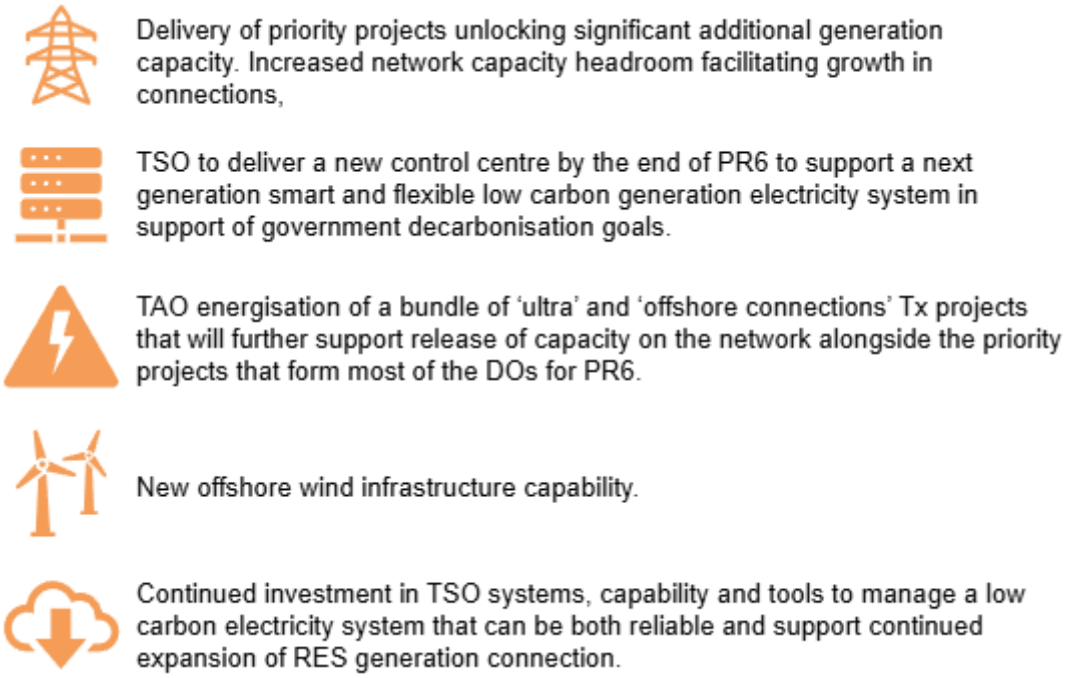
Alongside this Final Determination, the CRU has published a Response Paper (CRU2025212) summarising the comments received. The CRU has carefully considered all responses and has accounted for each relevant point within this Final Determination Paper.

What PR6 is expected to deliver for customers

The Network Needs Assessment paper (CRU202597) published alongside the Draft Determination highlighted the significant technical challenges from a network perspective in the achievement of Ireland's net zero ambition. This includes the need for substantial upgrades to the electricity grid to accommodate the anticipated increase in demand from the electrification of heat and transport, provision of new connections and integration of renewable energy sources, as well as to overcome existing network constraints.

The PR6 business plans submitted by the TSO and TAO focussed on addressing these issues. The CRU supports the need to invest in the network to provide sufficient capacity which is a critical enabler to economic growth and the drive to decarbonisation. A snapshot of what PR6 is expected to deliver for customers is set out below.

Figure 1: Expected Delivery in PR6



Review of Historic and Forecast Expenditure

The CRU has applied a rigorous cost assessment process that ensures only well-justified and efficient expenditure is included within the allowed revenues. This includes both an *ex-post*, or historic review, into the actual outturn expenditure incurred in PR5, and the associated outputs, and an *ex-ante* review into forecast expenditure for PR6. The steps taken and elements considered in the cost assessment are set out in the introduction to Section 3 below.

The following subsections set out a brief summary of the CRU's historic (2021 - 2025) and forecast (2026 - 2030) review of TSO and TAO costs.

Unless otherwise stated, all prices stated within this document are expressed as real prices at 2024 price levels, based on the Harmonised Index of Consumer Prices (HICP). Also note that for PR5 expenditure this is often referred to as outturn expenditure, although it includes a mix of actual outturn costs for 2021 - 2023, and a mix of some outturn and budgeted or forecast costs for 2024 - 2025.[2]

PR5 Historic Expenditure Review (2021 – 2025)

The TSO's expected controllable opex outturn for PR5 is €385.7m. This is €18.5m (5%) above the CRU allowance of €367.2m. The TSO's expected overall opex outturn for PR5 is €3,166.2m, including non-controllable and exceptional costs.

The TSO's spend on opex delivered, *inter alia*, Temporary Emergency Generation (TEG) and retention of existing generation units under the Security of Supply Programme, which were key measures in addressing the shortfall in generation capacity which caused a number of System Alerts in 2021 and 2022. The spend also delivered ancillary services (€1,134.3m), which are non-energy products required to ensure the secure operation of the transmission system.

The TAO's overall expected opex outturn for PR5 is €374.9m. This is €15.0m lower than the CRU allowance of €389.9m. This outcome has been delivered through an overspend on controllable opex of €14.2m and an underspend on non-controllable opex of €20.0m.

Table 1 provides a breakdown of the Final Determination for the TSO and TAO's historic opex. A more detailed explanation of the CRU's review is set out in Section 0.

[2] Since Draft Determination the CRU has received updated outturn information from both network companies for 2024. This has not been assessed as part of the updated historic review of costs as set out in this Final Determination primarily because of concerns in how these costs were presented relative to the 2024 costs included in the BPQ, submitted as part of the wider PR6 business plan submission. The updated outturn 2024 costs, as well as the 2025 outturn costs, when available, will be assessed as part of the CRU's annual tariff review and setting process.

Table 1: Summary of PR5 Opex

PR5 Transmission *Ex-post* Opex Allowance Categories	*Ex-ante* PR5 Allowance (€m)	PR5 Outturn/Forecast (€m)	*Ex-post* PR5 Allowance (€m)
Total TSO Controllable Opex	367.2	385.7	385.7
Total TSO Non-Controllable Opex	1.123.7	1,211.7	1,211.7
Total TSO Exceptional Items	-	1,568.8	1,568.8
Total TSO Opex	**1,490.9**	**3,166.2**	**3,166.2**
Total TAO Controllable Opex	192.5	197.6	197.6
Total TAO Non-Controllable Opex	197.3	177.3	177.3
Total TAO Opex	**389.9**	**374.9**	**374.9**
Total	**1,880.7**	**3,541.1**	**3,541.1**

The TSO's net outturn total capex is expected to be €347.8m, an overspend of €67.5m or 24% of the PR5 allowance. Non-network PR5 capex is forecast to be €204.6m, an overspend of €6.3m or 3% of the CRU PR5 allowance. EirGrid requested a number of in-period adjustments for non-network capex, which, *inter alia,* includes preparatory spend to facilitate the eventual incorporation of Offshore wind farms and new Interconnectors (Celtic and Greenlink) onto the grid.

The TAO's expected net outturn for PR5 is €1,185.0m which is an underspend of €117.7m when compared to the PR5 allowance. The underspend is primarily driven by a significant underspend on pipeline projects. The TAO forecasts delivery of 113.1km of overhead lines (OHLs), 137.2km of underground cables (UGCs), 14 transformer units and 274 switchgear units by the end of PR5.

Table 2 provides a breakdown of the Final Determination for the TAO and TSO's historic capex. A more detailed explanation of the CRU's decision is set out in Section 2.1.

Table 2: Summary of PR5 Capex

	Ex-ante PR5 Allowance (€m)	PR5 Outturn/Forecast (€m)	*Ex-post* PR5 Allowance (€m)
TSO Capex	280.3	347.8	347.8
TAO Capex	1,302.7	1,185.0	1,185.0
Total	**1,583.0**	**1,532.8**	**1,532.8**

PR6 Forecast Expenditure Review (2026 – 2030)

EirGrid as TSO and ESB Networks as TAO have requested a baseline PR6 transmission allowance of €4.1bn. ESB Networks, as TAO, has proposed baseline allowance proposals to account for uncertainty related to external factors. In addition to the baseline, ESB Networks identify the total costs needed to deliver against the targets and objectives associated with 2030 and PR6. These costs are separated in Table 3 below. The CRU's review of this forecast expenditure flagged concerns around instances of limited or insufficient information. In addition,

the PR6 allowances also reflect concerns around deliverability and the readiness for some of these investment programmes to proceed.

For controllable opex, the CRU has allowed a considerable increase for PR6 (*circa* 75%) when compared to the TSO's PR5 outturn. This reflects the CRU's commitment to ensure that the TSO has the resources and capability to deliver on the PR6 strategic objectives.

The difference between the Draft Determination proposals and the Final Determination allowances for the TSO is mainly driven by higher staff costs, which have increased by €51.7m following additional information from the TSO on the number of full-time equivalents (FTEs) currently employed. For the TAO, the increase is primarily due to higher allowed Transmission Operations costs. The TAO has provided evidence that the higher PR5 outturn for Transmission Operations, relative to the PR5 *ex-ante* allowance, is expected to represent the ongoing level of cost rather than a one-off, exceptional increase. This has been reflected in the allowances, resulting in a €7.9m increase in Transmission Operations relative to Draft Determination.

Table 3: PR6 Transmission Opex Final Determination

PR6 Transmission *Ex-ante* Opex Allowance Categories	Request (€m)	Baseline Allowance (€m)	High Allowance (€m)	DD – FD Baseline Variance (€m)	DD – FD High Variance (€m)
TSO Controllable Opex	950.3	837.4	920.5	+93.1	+96.2
TSO Non-Controllable Opex[3]	1,934.5	1,934.5	1,934.5	-	-
TSO Exceptional Items	745.4	745.4	745.4	-	-
Total TSO Opex (excluding Frontier Shift)	**3,630.2**	**3,517.3**	**3,600.4**	**+93.1**	**+96.2**
Total TSO Opex (including Frontier Shift)	**-**	**3,546.8**	**3,629.9**	**+95.5**	**+98.6**
TAO Controllable Opex	211.6	203.2	203.2	+10.4	+10.4
TAO Non-Controllable Opex	215.0	215.0	215.0	-	-
Total TAO Opex (excluding Frontier Shift)	**426.6**	**418.2**	**418.2**	**+10.4**	**+10.4**
Total TAO Opex (including Frontier Shift)	**-**	**419.5**	**419.5**	**+11.2**	**+11.2**
Total (excluding Frontier Shift)	**4,056.8**	**3,935.5**	**4,018.6**	**+103.5**	**+106.6**
Total (including Frontier Shift)	**-**	**3,966.3**	**4,049.4**	**+106.7**	**+109.8**

[3] Excludes TAO Payment, and PSO.

For capex, the TAO's capex requirement has also increased by *circa* 97% when compared to PR5 outturn. This substantial increase is reflective of the need for the transmission network to, amongst other legislative targets, have the ability to accommodate the anticipated increase in demand from the electrification of heat and transport, provision of new connections, integration of up to 80% of electricity from renewable sources by 2030, as well as to overcome existing network constraints to maintain security of supply and system resilience.

The CRU's PR6 capex Final Determination is summarised in Table 4 below.[4]

Table 4: PR6 Transmission Capex Final Determination

PR6 Transmission *Ex-ante* Capex Allowance Categories	PR6 Baseline Request (€m)	PR6 Total Request (€m)	PR6 Baseline Allowance (€m)	PR6 High Allowance (€m)	DD – FD Baseline Variance (€m)	DD – FD High Variance (€m)
Total TSO Capex	877.1	877.1	716.9	856.1	+57.2	+18.5
Total TAO Capex[5]	3,412.8	5,684.2[6]	3,016.0	5,684.2	-1,001.0	+8.7
Customer Contributions	-140.0	-340.0	-140.0	-340.0	-	-142.0
Total (net of customer contributions)	**4,149.9**	**6,221.3**	**3,592.9**	**6,200.3**	**-943.8**	**-114.8**

Finance and Cost of Capital

The CRU is separating Weighted Average Cost of Capitals (WACCs) for EirGrid (TSO) and ESB Networks (TAO/DSO) for PR6, accounting for the asset-light characteristics of the TSO directly in the cost of capital. Table 5 below summarises the TSO and TAO cost of capital for PR6.

[4] Although not included in the figures in this Final Determination, it should be noted that the total TAO capex submission includes the TSO network capex request which is invoiced to the TAO.
[5] TAO capex exclusive of TSO network capex invoiced to the TAO. No Frontier Shift adjustments have been applied to the *ex-ante* capex allowances.
[6] Note that the baseline forecast costs exceed the high case for CP0816 and CP1216. In these cases, the baseline value has been taken as the high case for consistency.

Table 5: Cost of Capital Estimates – TSO and TAO

Parameter	TAO PR6 FDs		TSO PR6 FDs	
	Lower	Upper	Lower	Upper
Benchmark cost of debt	1.49%	1.49%	1.46%	1.46%
Issuance costs	0.10%	0.20%	0.10%	0.20%
Cost of debt	**1.59%**	**1.69%**	**1.56%**	**1.66%**
Risk-free rate	0.75%	0.75%	0.75%	0.75%
Total market return	6.40%	6.80%	6.40%	6.80%
EMRP	5.65%	6.05%	5.65%	6.05%
Asset beta	0.31	0.35	0.50	0.55
Equity beta	0.69	0.78	1.11	1.22
Cost of equity (post-tax)	4.64%	5.46%	7.03%	8.14%
Tax	12.5%		15.0%	
Cost of equity (pre-tax)	**5.31%**	**6.23%**	**8.27%**	**9.58%**
Notional gearing	55%			
WACC (real, pre-tax)	**3.26%**	**3.74%**	**4.58%**	**5.23%**
Adjustment for inflation expectation	0.40%		0.40%	
WACC (real, pre-tax) after adjustment for inflation expectations	**3.66%**	**4.14%**	**4.98%**	**5.63%**
Cost of Capital	**4.00%**		**5.41%**	

The PR6 WACC estimate for TSO (onshore) is 5.41%, which is higher than the PR6 Draft Determination proposal of 5.23%. The CRU considers it appropriate to remunerate for the risk associated with high operational cost through the WACC rather than through a margin, as it is the allowed WACC that compensates the shareholders for systematic risk.

A new working capital mechanism has been introduced to help ESB Networks cover financing costs associated with pre-purchasing of stock and materials, and providing commitments for supply chain contracts in advance of assets becoming operational. This reduces financial risk, and supports business operations, driving benefit for consumers by supporting the timely, and efficient, delivery of key infrastructure.

The CRU is allowing a real pre-tax cost of capital of 4.00% for the TAO in the PR6 period. For PR6, the CRU has looked at estimating the cost of debt for the TAO by taking a weighted average of the embedded debt and new debt. As in the previous price reviews, the CRU has used a notional capital structure to ensure that the consumers only pay for an efficient cost of capital structure.

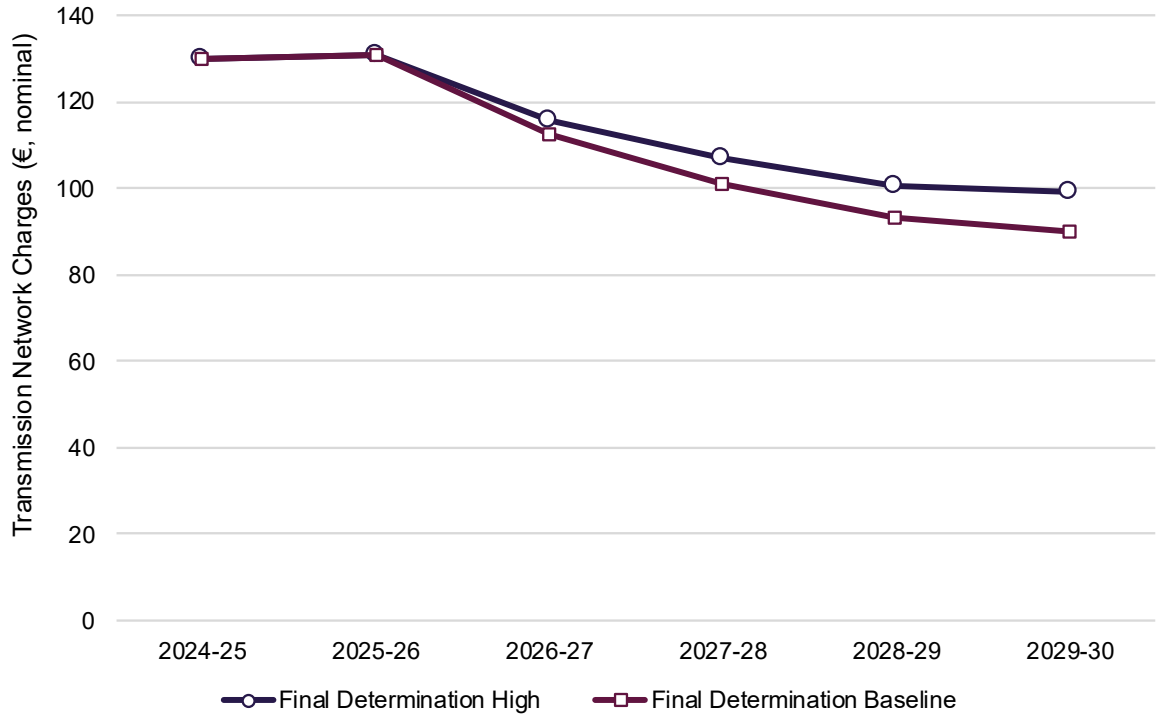
The PR6 Financeability Assessment (CRU2025201) suggests that based on the notional financial metrics of the utility businesses and investment plans over PR6, the TSO WACC of 5.41% and TAO WACC of 4.00% are consistent with the network companies being adequately financeable over the PR6 period with sufficient headroom.

The CRU's regulatory framework is viewed as supportive by the rating agencies S&P and Moody's. Moody's specifically has noted that ESB Networks benefit from a transparent, stable and predictable regulatory regime based on clearly defined risk and reward principles, with the stability and predictability of the regulatory regime assigned a AAA rating in Moody's scorecard assessment.[7]

Consumer Impact Summary

Transmission-related (including TAO and TSO) domestic network costs are expected to decrease (in nominal terms), when comparing relevant estimated charges for 2029/30 with 2024/25. The CRU's assessment included two different consumer impact scenarios relating to the Final Determination: a baseline and a high scenario. Figure 2 below shows the potential consumer impacts of the Final Determination on the transmission network charges which relate to an archetypical customer, as well as the impact of the baseline and high company ask.

Figure 2: Transmission Network Charges: Final Determination Domestic Customer Impacts (Nominal Values)



The general downward trend shown in Figure 2 is caused by a variety of factors including the forecasted decline in *inter alia* historic generator compensation costs (Article 13.7) and the security of supply programme. A key driver is the reduction in security of supply costs from 2024/25 (*circa* €0.3 billion allowance in 2025 allowed revenues (CRU202482)), down to zero by

[7] Moody's Credit Opinion for ESB – June 2025 (p.13)

the end of PR6.[8] This has a significant impact on the trend as it is part of the TSO's external costs, which are all recovered through Demand Transmission Use of System (DTUoS) tariffs. Transmission cost items which are classified as TSO internal costs or TAO costs are not entirely recovered through DTUoS only, which also means that the impact of increasing allowances in these categories in the Final Determination baseline scenario is slightly muted when it comes to the DTUoS charges.

[8] Final Determination baseline scenario values for security of supply over PR6 are presented in Table 42.

Public/Customer Impact Statement

The CRU's Final Determination sets the framework for how much revenue network companies can recover and what they must deliver in return. These decisions are critical for enabling higher levels of renewable energy, supporting decarbonisation, meeting climate targets, enhancing energy security, and promoting long-term price stability. They also directly affect consumer bills and the quality-of-service customers receive.

Ireland's electricity networks deliver secure electricity supplies to homes and businesses in the country. The CRU allows the network companies to charge money towards the cost of building, safely operating and maintaining the electricity system in Ireland. These charges are passed onto suppliers, which are then typically reflected in customers' electricity bills and make up the network companies' revenue allowances.

The CRU's role is to protect electricity customers by ensuring that the network companies spend customers' money appropriately and efficiently to deliver necessary services and make necessary investments in infrastructure. The CRU does this through what is called a price review which is carried out every five years. The current price review (PR5) started in 2021 and will end in 2025. PR6 will follow PR5 and will determine the use of system charges for the period 2026 to 2030, and therefore, will have an impact on customers' electricity bills over that period.

The transmission network and operation of same are critical to delivering electricity safely and reliably to homes and businesses across Ireland. Through this Final Determination, the CRU aims to strike the right balance between ensuring consumers only pay for well justified plans and proposals and the need to invest in smarter, greener and more resilient energy for the future.

The allowed revenues set out in this Final Determination paper are targeted at delivering value for customers while enabling the network companies to deliver on outcomes and objectives through PR6 linked to Ireland's decarbonisation, climate change and renewable energy ambitions. The CRU considers it critical that throughout PR6 network companies provide resilient electricity networks and supplies while supporting high-quality, secure and cost-effective services to customers and networks users.

The impact of these Final Determination decisions on electricity consumers has been analysed in detail in the accompanying Information Paper on the topic (CRU2025198). Overall, transmission-related network charges for the archetypical domestic customer are expected to decrease (in nominal terms) by €40 in the Final Determination baseline scenario and by €31 in the high scenario, when comparing relevant forecast charges for 2029-30 with 2024-25.

Table of Contents

Glossary of Terms and Abbreviations 4

1. Background 8

1.1. The CRU's Legislative Remit 9
1.2. PR6 Strategy 10
1.3. PR5 Outturn Figures 12
1.4. How to Navigate This Paper 12
1.5. Conduct of the Review 14
1.6. Related Documents 16

2. Review of Allowed Expenditure between 2021 – 2025 17

2.1. Review of Historical Capital Expenditure 17
2.1.1. Review of TSO and TAO Capital Expenditure 18
2.1.2. Review of TSO Capital Expenditure 19
2.1.2.1. Network Capex 19
2.1.2.2. Non-Network Capex 19
2.1.3. Review of TAO Capital Expenditure 21
2.2. Review of Historical Operational Expenditure 22
2.2.1. Review of TSO Operational Expenditure 22
2.2.1.1. TAO Payment 23
2.2.1.2. PSO Levy 24
2.2.2. Review of TAO Operational Expenditure 24
2.2.2.1. Miscellaneous 26
2.3. Conclusions 26

3. Review of Forecast Expenditure 2026 – 2030 28

3.1. Forecast Capital Expenditure 29
3.1.1. Review of Forecast Network Capital Expenditure 30
3.1.1.1. Integrated Transmission Programme Baseline 1 31
3.1.1.2. TSO Network Capital Expenditure 34
3.1.1.3. TAO Network Capital Expenditure 38
3.1.2. Non-Network Capital Expenditure 45
3.1.2.1. TSO Non-Network Capital Expenditure 45
3.1.2.1.1. TSO Transformation 46
3.1.2.1.2. Technology Resilience and Modernisation 49
3.1.2.1.3. Power System Capability Enhancement 50
3.1.2.1.4. Digital Transformation 51

3.1.2.1.5. Celtic Operational Readiness 52
3.1.2.1.6. Cyber Security 52
3.1.2.1.7. TSO/DSO Coordination 53
3.1.2.2. TSO Non-Network Final Determination Summary 53
3.1.2.3. TAO Non-Network Capital Expenditure 54
3.1.3. Allowed PR6 Capital Expenditure 55
3.2. Forecast Operational Expenditure 57
3.2.1. Review of TSO Forecast Operational Expenditure 57
3.2.1.1. TSO Opex 59
3.2.1.1.1. Staff and Staff Related Costs 59
3.2.1.1.2. Contractors 61
3.2.1.1.3. Professional Services 63
3.2.1.1.4. Premises 64
3.2.1.1.5. IT Costs 65
3.2.1.1.6. Insurance 66
3.2.2. Review of TAO Forecast Operational Expenditure 67
3.2.2.1. TAO Opex 68
3.2.2.1.1. Transmission Operations 69
3.2.2.1.2. Planned Maintenance 70
3.2.2.1.3. Professional Fees 71
3.2.3. Frontier Shift 71
3.3. Conclusions 74

4. The Regulated Asset Base 75

4.1. Introduction 75
4.2. Value and Composition 76
4.3. Asset Lives Applied to the RAB 77
4.4. Depreciation Methodology 80
4.5. Replaced Assets 81
4.6. Capital Expenditure Approved but not Incurred 82
4.7. Additions to the RAB 82
4.7.1. Interest During Construction 82
4.7.1.1. Capital Contributions and Grants 83
4.8. Working Capital Mechanism 83
4.9. Conclusions 84

5. Cost of Capital 85

5.1. Introduction 85
5.2. Methodology for Setting the Cost of Capital 86
5.2.1. Key Considerations in Setting the WACC 86
5.2.2. Building Blocks of WACC 88
5.3. Estimating the PR6 Cost of Capital 89
5.3.1. Cost of Equity 90

5.3.2. Cost of Debt 91
5.3.3. Gearing 92
5.4. Conclusions 92
5.4.1. TSO WACC Estimate 93
5.4.2. TAO WACC Estimate 95
5.4.3. Celtic Interconnector 95
5.4.3.1. Celtic WACC Estimate 97
6. Financeability 98
6.1. Summary and Conclusions 98
7. Allowed Revenues 105
7.1. Revenue and Profiling 105
Appendix 1 – PR6 Transmission Capex 107
Appendix 2 – PR6 Transmission Opex 109
Appendix 3 – Valuation of the Regulatory Asset Base 111

Glossary of Terms and Abbreviations

Abbreviation or Term	Definition or Meaning
the Act	Electricity Regulation Act, 1999
AICR	Accrual-based Interest Coverage Ratio
AIF	Agile Investment Framework – PR5
AIMF	Agile Investment and Monitoring Framework – PR6
BAU	Business As Usual
BPQ	Business Plan Questionnaire
Capex	Capital Expenditure
CAP	Climate Action Plan
CAPM	Capital Asset Pricing Model
CAV	Closing Asset Value
CBCA	Cross-Border Cost Allocation
CEPA	Cambridge Economic Policy Associates
CoD	Cost of Debt
CoE	Cost of Equity
CORESO	CooRdination of Electricity System Operators
CPP	Committed Programme Parameter
CRE	Commission de Régulation de L'Énergie
CRU	Commission for Regulation of Utilities
DAC	Designated Activity Company
DAO	Distribution Asset Owner – ESB Networks

DD	Draft Determination
DETE	Department of Enterprise, Tourism and Employment
DMS	Dimson, Marsh and Staunton
DO	Delivery Obligation
DSO	Distribution System Operator – ESB Networks
DTUoS	Demand Transmission Use of System
DUoS	Distribution Use of System
EBIT	Earnings Before Interest and Taxes
ECP	Enduring Connection Policy
EI	Energisation Instruction
EIB	European Investment Bank
EMRP	Equity Market Risk Premium
EMS	Energy Management System
ESRI	Economic Research and Social Institute
ENA	Energy Networks Association
FASS	Future Arrangements for System Services
FFO	Funds From Operations
FTE	Full-time Equivalent
GHD	Gutteridge, Haskins and Davey
GSS	Generation and System Services
HICP	Harmonised Indices of Consumer Prices
IDC	Interest During Construction
ITP	Integrated Transmission Programme
MEAV	Modern Equivalent Asset Value

MEC	Maximum Export Capacity
MVA	Megavolt Ampere
NCCS	Network Code on Cybersecurity
NIS 2	Directive (EU) 2022/2555 of the European Parliament and of the Council of 14 December 2022 on measures for a high common level of cybersecurity across the Union
OAO	Offshore Asset Owner
OAV	Opening Asset Value
OECD	Organisation for Economic Co-operation and Development
OHL	Overhead Lines
Opex	Operational Expenditure
ORESS	Offshore Renewable Electricity Support Scheme
OTP	Outage Transformation Programme
PC5	Price Control 5
PI	Performance Incentive
PR	Price Review
PRSI	Pay Related Social Insurance
PSO	Public Service Obligation
QRA	Quantitative Risk Assessment
RAB	Regulated Asset Base
RCF	Retained Cash Flow
RES-E	Renewable Energy Source – Electricity
RESS	Renewable Electricity Support Scheme
RPE	Real Price Effects

SaaS	Software as a Service
S&D	Scheduling and Dispatch
SCADA	Supervisory Control and Data Acquisition
SEM	Single Electricity Market
SMP	Strategic Markets Programme
SONI	System Operator for Northern Ireland
SOPCM	System Operator Preferred Connection Method
TAO	Transmission Asset Owner – ESB Networks
TEG	Temporary Emergency Generation
TMR	Total Market Return
TSO	Transmission System Operator – EirGrid
TUoS	Transmission Use of System
UGC	Underground Cables
WACC	Weighted Average Cost of Capital
WCF	Working Capital Facilities

1. Background

The CRU is responsible for the economic regulation of the system operators and asset owners for electricity transmission and distribution systems in Ireland. To do this, the CRU carries out reviews of the allowed revenue for the transmission and distribution businesses through price reviews. Price reviews set the revenue that the relevant network company can recover from electricity consumers and are set every five years. The transmission business consists of EirGrid, licensed by the CRU as the TSO and ESB, acting through its ESB Networks business unit, is the licensed TAO. ESB Networks DAC is licensed by the CRU as Distribution System Operator (DSO), and ESB, acting through its ESB Networks business unit, is the licensed Distribution Asset Owner (DAO).

In December 2020, the CRU set its Final Determination for the Price Review 5 (PR5) period for EirGrid as TSO, and for ESB Networks as TAO and DSO/DAO. PR5 comes to an end in 2025, therefore, the CRU has undertaken a review of the allowed revenue for the transmission and distribution businesses for the next price review period (PR6). PR6 will cover the five-year period from 2026 to 2030. This Final Determination outlines the revenue that EirGrid as TSO and ESB Networks as TAO are allowed recover and access (as part of the AIMF) during a the PR6 period.

In recent years, there have been major policy developments at national and European level that have and will continue to drive significant change in the energy sector. European policies have set EU-wide targets to achieve carbon neutrality (net-zero emissions) by 2050. To facilitate this, national policies recognise the need to promote the large-scale deployment of renewables which will be critical to decarbonising the power sector as well as enabling the electrification of other technologies. The major policy developments that impact the strategic context of PR6 are described in detail in Section 2 of the PR6 Strategy Paper.[9]

Having considered all responses to the Draft Determination (CRU202588) published in July, this paper sets out the Final Determination on the *ex-post* review of PR5 and the *ex-ante* allowances for the PR6 period.

The CRU has acquired the services of economic and engineering experts to assist in the review of the TSO and TAO's historic costs and performance in PR5, forecast costs for PR6, and setting allowed revenues. Cambridge Economic Policy Associates (CEPA) with the support of Gutteridge, Haskins and Davey (GHD) were procured to provide advice on the economic, policy and technical aspects of the review. Specifically, GHD reviewed and provided advice on the TSO

[9] CRU202427 – Price Review Six Strategy Paper

and TAO's capex costs while CEPA reviewed and provided advice on the TSO and TAO's opex costs and the Cost of Capital.

The advice provided by the CRU's consultants informed the decisions outlined in this Final Determination. Supporting reports provided by both GHD and CEPA are published alongside this paper. To avoid repetition, this paper does not reproduce the analysis carried out by GHD and CEPA but focuses on the conclusions. Accordingly, this Final Determination should be read in conjunction with the CEPA and GHD reports in order to gain a full understanding of all aspects of the review of the TSO and TAO PR6 submissions.

1.1. The CRU's Legislative Remit

Under Section 35 of the Electricity Regulation Act, 1999 ('the Act'), the CRU approves charges for the use of the electricity transmission system in Ireland. An extract from Section 35 is below.

> **35** – (1) Subject to *subsection (2)*, within such time as the Commission may direct, the Board shall prepare a statement for the approval of the Commission setting out the basis upon which charges are imposed —
>
> *(a)* for use of the transmission or distribution system of the Board, and
>
> *(b)* for connection to the transmission or distribution system of the Board.
>
> (2) The Commission may give directions to the Board from time to time in respect of the basis for charges for use of and connection to the transmission system or distribution system of the Board.
>
> […]
>
> (4) A charge for connection to or for the use of the transmission or distribution system of the Board shall be calculated in accordance with directions given by the Commission under this section so as to enable the Board to recover— (a) the appropriate proportion of the costs directly or indirectly incurred in carrying out any necessary works, and (b) a reasonable rate of return on the capital represented by such costs.
>
> (5) The Commission, solely, will determine what constitutes an "appropriate proportion" referred to in subsection (4)(a) and a "reasonable rate of return" referred to in subsection (4)(b).
>
> […]
>
> (7) The Commission shall publish the statement referred to in subsection (1).
>
> (8) With a view to increasing transparency in the market and providing all interested parties with all necessary information and decisions or proposals for decisions concerning transmission and distribution tariffs, as referred in Article 60(3) of the 2019 Internal Electricity Market Directive, the Commission shall make publicly available the detailed methodology and underlying costs used for the calculation of the relevant network tariffs, while preserving the confidentiality of commercially sensitive information.

In accordance with Section 35 of the Act, this document outlines the CRU's decisions on the revenue that the ESB in its capacity as the licensed TAO and EirGrid, as the licensed TSO will be allowed to recover from TUoS customers during the period from 2026 to 2030. In accordance with Section 35(4), these charges are to be calculated to enable recovery of:

- the appropriate proportion of the costs directly or indirectly incurred in carrying out any necessary works; and
- a reasonable rate of return on the capital represented by such costs.
- The Infrastructure Agreement between the TSO and TAO, entered into on 16 March 2006 pursuant to the requirements of S.I. No. 445 of 2000, as amended) governs the arrangement for payments between the TSO and TAO of the TUoS collected.

The rationale for the CRU's decisions is explained in detail in the remainder of this paper. The level of revenue (historical and future) is detailed in Sections 2 and 3.

Section 36 of the Act requires the statement of charges, prepared in accordance with Section 35, be submitted to the CRU for approval. The statement of charges will not take effect until approved by the CRU.

In accordance with Section 35(7) of the Act, the TSO's approved statement of charges for each year of PR6 will be published annually by the CRU in August for the upcoming 1 October to 30 September tariff period.

1.2. PR6 Strategy

On 24 April 2024, the CRU published the PR6 Strategy Paper. This paper sets out the CRU's objectives and preferred outcomes for PR6.

In recent years, there have been major policy developments at national and European level that have and will continue to drive significant change in the energy sector. The publication of the CAP24[10] was the third annual update to the CAP19[11] and reaffirmed the challenge ahead for the electricity sector in Ireland. These developments are set out in greater detail in the PR6 Strategy Paper.

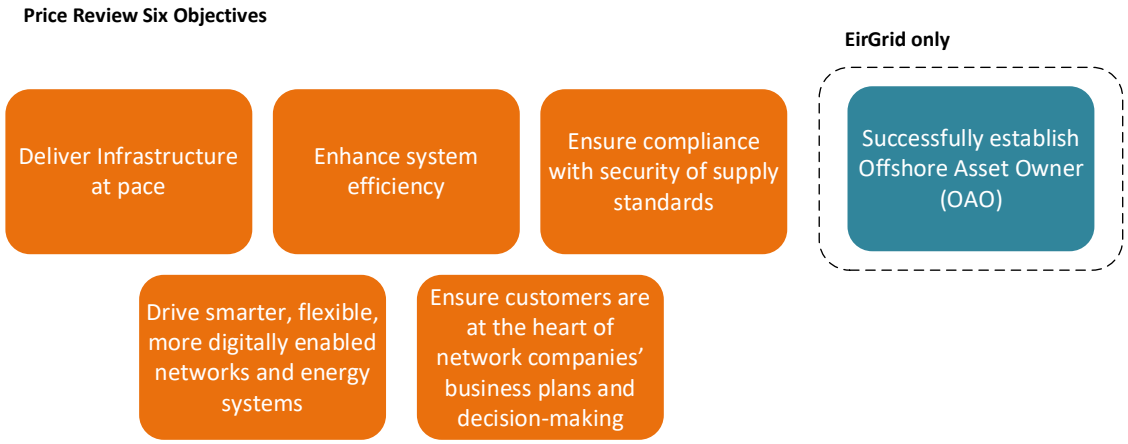
[10] Climate Action Plan 2024
[11] Climate Action Plan 2019

PR6 will be a critical price review for network companies to fulfil their role in the delivery of Ireland's decarbonisation and renewable electricity ambitions. It is also important that throughout PR6, network companies continue to provide resilient energy networks and supplies while also ensuring high-quality and secure services to customers and networks users. To achieve this, CRU has set three outcomes that it expects network companies to deliver. Transforming Ireland's electricity networks as part of the energy system transition, presents a significant challenge that requires emphasis on shaping PR6 to be a more outcomes focused price control.

- **Decarbonised electricity:** Network companies must facilitate realisation of Ireland's decarbonisation ambitions, enabling high levels of renewable electricity integration, driving an environmentally sustainable, low carbon energy system.
- **Secure and resilient networks and supplies:** Network companies must ensure safe, secure, resilient electricity networks and supplies which customers can rely on.
- **Empower customers:** Network companies must deliver high quality and reliable services to customers, ensuring their voice is heard and reflected in the work they do, and that the cost of the transition is minimised.

To ensure delivery of these key outcomes, the CRU considers the objectives in Figure 3 to be central to the network companies for PR6:

Figure 3: The CRU's PR6 Objectives



- **Deliver infrastructure at pace** to support decarbonisation, the realisation of Ireland's renewable energy and climate change targets and reducing the cost of constraints to consumers.
- **Enhance system efficiency** while continuing to meet the needs of the network and protecting the long and short-term customer interest.

- **Ensure compliance with security of supply standards** by efficiently managing and developing the networks.
- **Drive smarter, flexible, more digitally enabled networks** and energy system to improve capabilities and ongoing efficiency.
- Customers at the heart of business planning and decision making.
- The EirGrid only objective to **Successfully establish Offshore Asset Owner (OAO)** is discussed in a separate Final Determination published alongside this paper.

1.3. PR5 Outturn Figures

Within this paper, the figures provided by the TSO and TAO on their respective expenditure during the PR5 period have been labelled as actual or outturn values. This is not strictly correct. In some cases, the 2024 and 2025 values are the TSO and TAO's best estimate of the expenditure they will incur in both years.

The final values for 2024, which were received post Draft Determination, and 2025 will be reviewed in 2026 and if necessary, any under or over-recovery from the TUoS customer will be corrected at that time to reflect the actual outturn values through the annual tariffing process.

1.4. How to Navigate This Paper

A high-level summary of the approach the CRU has adopted to determine the revenue that the TSO and TAO can recover from TUoS customers during the period 2026 to 2030 is set out below. The CRU recognises that this is a large paper and covers a range of decisions. To assist the readers, the below summarises the key sections of the paper.

Section 2: Review of Allowed Expenditure between 2021 – 2025

- **Section 2.1: Review of Historic Capital Expenditure**

  Review of the capex incurred by the network company over the period 2021 to 2025 and a summary of key decisions provided.

- **Section 2.2: Review of Historic Operational Expenditure**

  Review of the opex incurred by the network company over the period 2021 to 2025 and a summary of key decisions provided.

Section 3: Review of Forecast Expenditure between 2026 – 2030

- **Section 3.1: Review of Forecast Capital Expenditure**

  Review of the capex programme allowed for the PR6 period, as forecasted by the network company and a summary of key decisions provided.

- **Section 3.2: Review of Forecast Operational Expenditure**

  Review of the opex programme allowed PR6 period, as forecasted by the network company and a summary of key decisions provided.

Section 4: The Regulatory Asset Base (RAB)

- Summarises the adjusted RAB that will be used for the forthcoming review period, as included in the CRU's Price Review revenue models, published alongside this paper.
- Provides key decisions on elements of RAB valuation and composition including depreciation approach and methodology.

Section 5: Determining the Cost of Capital

- Summarises the cost of capital that will be used for the forthcoming review period, as included in the CRU's price review revenue models, published alongside this paper.

Section 6: Financeability

- Summarises the financeability assessment.

Section 7: Determining the Allowed Revenue

- Summarises the allowed revenues for the TSO and TAO (which will be recovered from the TUoS customer) for each calendar year within the period 2026 to 2030. This revenue feeds through into the setting of the annual TUoS tariffs, which cover the period 1 October to 30 September.

The CRU has assumed that the TSO and TAO functions will continue to remain as distinct commercial semi-state enterprises, each operating under its own independent governance structure for the duration of the review, and there will be no substantial changes made to its structure, although improvements in their independence and governance are expected over the period.

Therefore, the transmission allowed revenues for 2026 to 2030 have been set on the basis of the current industry structure and the CRU is assuming that this structure will be in place for the entire PR6 period, allowing for the expected changes in the role of the TSO and TAO noted above. Should this position change, or if it is likely to change, at some point over the five years of this price review period (2026 to 2030), the CRU will take the appropriate steps to review the regulatory structures and revenues in place.

1.5. Conduct of the Review

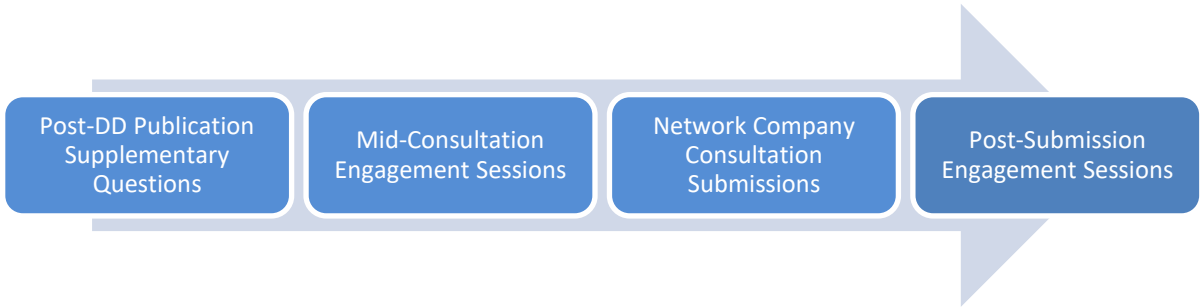
To ensure that the CRU and its advisors attained an adequate understanding of the TSO's and TAO's business plans, the CRU engaged with both parties to ensure that the relevant data was provided in a useable format. Figure 4 sets out the CRU's PR6 engagement with network companies prior to the publication of the Draft Determination Paper.

Figure 4: CRU's PR6 Engagement with Network Companies



The CRU also engaged with the TSO and TAO prior to and after the close of the Draft Determination Consultation. Figure 5 summarises the CRU's PR6 engagement with network companies prior to the publication of this Final Determination Paper.

Figure 5: Engagement prior to Final Determination



Engagement for PR6 had some notable changes to PR5. In particular, the CRU began using dedicated supplementary questions to obtain more detailed information on specific queries and set realistic response times for the network companies. Following publication of Draft

Determination, the same process was used to allow the network companies to seek clarification on the proposals put forward by the CRU. There has also been a significant increase in the level of engagement with EirGrid and ESB Networks, including (but not limited to):

Prior to Draft Determination

- 5 Workshops on the Business Plan Submissions prior to issuance to EirGrid by CRU;
- 6 Information Sessions with EirGrid prior to Business Plan Submissions;
- 6 Workshops and deep-dive sessions with EirGrid post-Business Plan Submissions; and
- *Circa* 158 supplementary questions issued.

The aim of this engagement was to clarify significant points related to each network companies' submissions, and to allow CRU to seek clarifications to better understand the network companies' justifications.

Between Draft Determination and Final Determination

- 3 Workshops with EirGrid on the Draft Determination proposals during the consultation period;
- 47 supplementary questions responded to;
- Weekly Workshops with both network companies on the PR6 User Guide; and
- 5 Workshops with EirGrid on the CRU's Final Determination decision following the consultation period.

The aim of this engagement was to provide the network companies the opportunity to seek clarification on the CRU's Draft Determination proposals and for the CRU to brief the network companies on the CRU's Final Determination decisions.

The engagement allowed the CRU, with the assistance of its advisors, to complete a comprehensive review of the TSO's and TAO's historic, forecast and additional information submissions and ultimately lead to the development of the decisions outlined in this paper.

The CRU has updated the network companies on the progress of the Final Determination and held *ad hoc* meetings to discuss various topics of concern to each network company. This included an in-person workshop where the CRU's proposals for the Final Determination were shared. Prior to the publication of the Final Determination, both parties were provided with an opportunity to review the documentation for factual accuracy.

1.6. Related Documents

Further background relevant to this decision document can be found in the following documents:

Table 6: Summary of relevant PR6 Final Determination documents

CRU	Price Review Six Summary Paper	CRU2025193
CRU	Price Review Six Offshore Paper	CRU2025196
CRU	Price Review Six Regulatory Framework	CRU2025197
CRU	Price Review Six Impact Analysis Note	CRU2025198
CRU	Price Review Six Infographic	CRU2025199
CRU	Price Review Six User Guide	CRU2025200
CEPA	Price Review Six Onshore Cost of Capital and Financeability Assessment	CRU2025201
CEPA	PR5 and PR6 TSO Opex Cost Assessment	CRU2025203
CEPA	PR5 and PR6 TAO Opex Cost Assessment	CRU2025204
GHD	Review of TSO and TAO Capex PR5 and PR6	CRU2025206
CRU	PR6 TSO Revenue Model	CRU2025209
CRU	PR6 TAO Revenue Model	CRU2025210
CRU	Price Review Six Response Paper	CRU2025212

2. Review of Allowed Expenditure between 2021 – 2025

This part of the paper sets out the CRU's Final Determination of allowed TSO and TAO expenditure for PR5 (2021 – 2025), following the historic review of outturn expenditure and the review of Draft Determination responses. The following sections will summarise the:

- Review of Historical Capital Expenditure; and
- Review of Historical Operational Expenditure.

The main objectives in the PR5 review of the TSO and TAO's historical expenditure are to assess whether the expenditure has been incurred efficiently and the expected benefits for customers have been achieved. Consistent with previous price reviews, the following areas were examined in detail:

- Comparing the outturn expenditure (and currently projected for 2024 and 2025) with the allowed expenditure;
- Understanding the differences between allowed expenditure and the outturn expenditure; and
- Assessing cost drivers and their impact on performance.

2.1. Review of Historical Capital Expenditure

This section examines the TSO and TAO's capex over the PR5 period (2021 – 2025). The outturn expenditure is assessed, looking at the output in terms of delivery and efficiency. Table 7 summarises the outcome of the historic capex review for TSO and TAO.

A more detailed description and breakdown is provided in an accompanying Review of TSO and TAO Capex PR5 and PR6 (CRU2025206).

Table 7: Summary of Historical Capex (2021 - 2025) Review

Cost Category	*Ex-ante* PR5 Allowance (€m)	PR5 Outturn (€m)	*Ex-post* PR5 Allowance (€m)
TSO Capex	280.9	347.8	347.8
TAO Capex	1,302.7[12]	1,185.0	1,185.0
Total	**1,583.6**	**1,532.8**	**1,532.8**

Please note that all costs set out in the review of historic capex are in 2024 prices and some costs are rounded to the nearest €0.1m.[13]

2.1.1. Review of TSO and TAO Capital Expenditure

The CRU is allowing €1,532.8m of capex related to network and non-network investments for both the TSO and TAO following the *ex-post* review for PR5. This includes €347.8m of network and non-network capex for the TSO and €1,185.0m of network capex for the TAO.

The final outturn for the PR5 period is estimated as €1,532.8m, which results in a total capex underspend of €50.9m relative to the allowed capex revenue approved by the CRU. Having reviewed the advice of GHD, the full underspend appears largely due to significant underspends by the TAO in 2021 and 2022 of €143.0m and €79.9m, respectively. The CRU is allowing the full outturn of €347.8m of TSO capex and €1,185.0m of TAO capex as reasonable in PR5.

The total PR5 capex (TSO and TAO) compared to the PR5 allowance is set out in Table 8 below.

Table 8: PR5 Transmission Capital Expenditure

Category	2021 € m	2022 € m	2023 € m	2024 € m	2025 € m	PR5 Total € m
TSO Network Capex Outturn	16.6	13.0	26.9	29.7	57.2	143.5
TSO Network Capex Allowance	24.1	22.4	16.6	11.5	8.0	82.6
TSO Network Capex Variance	-7.4	-9.4	10.3	18.2	49.2	60.9
TSO Non-Network Capex Outturn	9.7	17.6	16.0	61.7	99.3	204.3
TSO Non-Network Capex Allowance	11.1	14.8	26.3	37.3	108.8	198.3
TSO Non-Network Capex Variance	-1.4	2.8	-10.3	24.4	-9.5	6.0
TAO Network Capex Outturn	195.2	204.7	234.9	263.3	286.8	1,185.0
TAO Network PR5 Allowance	338.2	284.6	248.2	228.9	202.8	1,302.7
TAO Network Capex Variance	-143.0	-79.9	-13.2	34.4	84.0	-117.7

[12] This figure represents project related network capex and excludes adjustments including TAO Adjustment, Interest During Construction, Protection, Telecoms and Station Security, and Customer Contributions.
[13] For the exact amounts allowed in the PR6 Final Determination, please refer to the PR6 Transmission model published alongside this paper.

2.1.2. Review of TSO Capital Expenditure

As shown in Table 8, the TSO is projecting a €60.9m or 74% overspend in network capex for PR5. The largest percentage annual increases are forecast in 2024 (158%) and 2025 (615%). €113.9m of the €143.5m is forecast to be spent on projects envisioned at PR5 Final Determination. The remainder of the TSO network capex spend (€29.6m) is attributed to new projects added in PR5 that were not accounted for within the allowance. The TSO was allowed €32.1m for projects that it did not progress during PR5 and that it does not forecast any spend for.

2.1.2.1. Network Capex

Draft Determination

The TSO's outturn costs of €143.5m corresponded to development of a number of projects that were not initially included in the original PR5 Business Plan submission and subsequent Final Determination allowance. The reporting of outturn spend for such new projects, along with spend on projects that were included in the PR5 Final Determination allowance, was deemed to be reasonable based on identification of new requirements during the period.

Summary of Responses

No response was provided to this proposal.

Final Determination

The CRU's position from Draft Determination is unchanged, i.e. under Final Determination, the CRU is allowing €143.5m for PR5 outturn network capex for the TSO.

2.1.2.2. Non-Network Capex

Draft Determination

Non-network capex was subject to substantial change in the PR5 period. An additional allowance of €122.7m was granted on top of the initial allowance of €75.6m, an additional 162%. There was an overall underspend of €11.6m on the original allowance, offset by the positive variance observed for the elements subject to in-period adjustment (€17.5m). The in-period adjustments for non-network capex requested by the TSO, *inter alia*, includes preparatory spend to facilitate the eventual incorporation of Offshore wind farms and new Interconnectors (Celtic and Greenlink) onto the grid.

The CRU were satisfied that the aforementioned variations in outturn non-network capex spend vs. forecast are reasonable and have been suitably explained by the TSO and proposed providing the full outturn allowance of €204.3m.

Summary of Responses

No response was provided to this proposal.

Final Determination

The CRU's position from Draft Determination is unchanged, i.e. under Final Determination, the CRU is allowing €204.3m for PR5 outturn non-network capex for the TSO.

Further analysis of the TSO's network and non-network capex is detailed in the Review of TSO and TAO Capex PR5 and PR6 (CRU2025206) and a summary of the TSO's PR5 capex allowance is set out in Table 9 below.

Table 9: TSO *Ex-post* PR5 Capex Allowance

PR5 TSO *Ex-post* Capex Allowance Categories	Outturn/Forecast (€m)	Final Determination PR5 Total (€m)
TSO Network Capex Outturn/Forecast	**143.5**	**143.5**
TSO Non-Network Capex Actual/Forecast		
1. IT Asset Replacement	26.8	26.8
2. Cloud Hosting Transition	0.7	0.7
3. IT Operating Model Review	1.8	1.8
4. Resilience & Market Complexity	4.3	4.3
5. Cyber Security	2.9	2.9
6. Facilities	6.8	6.8
7. Sustainability & Decarbonisation	12.9	12.9
8. Operate, Develop & Enhance Grid	7.9	7.9
9. Engage for Better Outcomes	0.0	0.0
Subtotal (original PR5 initiatives)	64.1	64.1
Market-related functions (FASS, SMP, Market System Release Capital, Celtic, S&D)	110.1	110.1
Non-Market-related functions	30.2	30.2
TSO Total Non-Network Capex Allowance	**204.3**	**204.3**
Total	**347.8**	**347.8**

2.1.3. Review of TAO Capital Expenditure

Draft Determination

Similarly to the TSO, the TAO's outturn costs of €1,185.0m included work to progress a number of projects that were not initially included in the original PR5 business plan submission and subsequent Final Determination allowance. The reporting of outturn spend for such new projects, along with spend on projects that were included in the PR5 Final Determination allowance, was deemed to be reasonable based on identification of new requirements during the period.

Compared to targets set as part of their PR5 allowance, the TAO underdelivered in terms of overhead lines, but overdelivered in terms of underground lines, transformers and switchgear.

Summary of Responses

No response was provided to this proposal.

Final Determination

The CRU's position from Draft Determination is unchanged, i.e. under Final Determination, the CRU is allowing €204.3m for PR5 outturn network capex for the TAO.

Table 10: TAO *Ex-post* Capex PR5 Allowance

PR5 TAO *Ex-post* Network Capex Allowance Categories	Allowance (€m)	Final Determination PR5 Total (€m)
PR5 project not progressed	43.4	-0.1
PR5 pipeline project not progressed	363.2	-
Project with no PR5 TAO allowance – not progressed	-	-
PR5 project progressed	741.6	716.6
PR5 pipeline project developed	154.4	92.5
Project with no PR5 TAO allowance – progressed	-	323.6
Project with no PR5 TAO allowance – adjustments	-	-3.0
Reconciliation	-	55.3
Total	**1,302.7**	**1,185.0**

2.2. Review of Historical Operational Expenditure

This section sets out the assessment of the TSO and TAO's opex over the PR5 period (2021 to 2025). The outturn expenditure is assessed, looking at the output in terms of delivery and efficiency. Table 11 summarises the outcome of the historic opex review for TSO and TAO. Note that the TSO's non-controllable and exceptional items cost categories are presented here but the primary focus of the review was on the TSO's controllable costs.

A more detailed description and breakdown is provided in the PR5 and PR6 TSO Opex Cost Assessment (CRU2025203) and PR5 and PR6 TAO Opex Cost Assessment (CRU2025204). Please note that all costs set out in the review of historic opex are in 2024 prices and some costs are rounded to the nearest €0.1m.

Table 11: Summary of Historical Opex (2021 - 2025) Review

PR5 TSO *Ex-post* Opex Allowance Categories	Outturn/Forecast (€m)	Final Determination PR5 Total (€m)
Total TSO *Ex-post* Controllable Opex Allowance	385.7	385.7
Total TSO *Ex-post* Non-Controllable Opex Allowance	1,211.7	1,211.7
Total TSO *Ex-post* Exceptional Items Opex Allowance	1,568.8	1,568.8
Total	**3,166.2**	**3,166.2**
PR5 TAO *Ex-post* Opex Allowance Categories	**Outturn/Forecast (€m)**	**Final Determination PR5 Total (€m)**
Total TAO *Ex-post* Controllable Opex Allowance	197.6	197.6
Total TAO *Ex-post* Non-Controllable Opex Allowance	177.3	177.3
Total	**374.9**	**374.9**

2.2.1. Review of TSO Operational Expenditure

The TSO's actual/forecast expenditure for PR5 is set out in Table 12. The CRU's Draft Determination position is unchanged, i.e. the expenditure is allowed in full for Final Determination.

Overall, the TSO's expected opex outturn for PR5 is circa €3,166.2m. This is €1,674.9m (112%) above the CRU allowance of €1,491.3m. The TSO is expected to spend €1,211.7m in non-controllable costs over PR5. This represents €87.6m (8%) overspend relative to the PR5 allowance. The TSO also spent €1,568.8m on Exceptional Items, largely consisting of Security of Supply costs which totalled €1,314.0m.

Table 12: TSO PR5 Opex Expenditure

PR5 Costs	PR5 Allowance (€m)	Actual / Forecast (€m)
Staff and related costs	207.3	200.5
Contractors	9.8	40.4
Telecommunications	32.4	27.5
Premises	34.6	32.4
IT Costs	47.5	43.9
Insurance and Compensations	1.8	4.5
Public Engagement	15.9	11.3
Professional Services	25.0	42.1
Grid Maintenance & Client Engineering	3.9	5.0
Rates	3.5	3.1
Promotion of Research	2.7	2.5
Intercompany Recharges	-18.2	-27.5
PR5 Reporting Requirement	0.9	0.0
Total Controllable Opex	**367.2**	**385.7**
Inter TSO Compensation	12.3	26.0
CORESO Subscription	3.3	4.9
Interconnector Services	4.8	8.0
CRU Levy	5.8	10.5
DUoS Costs	19.0	28.1
Ancillary Services	1,078.9	1,134.3
Total Non-Controllable Costs	**1,124.1**	**1,211.7**
Exceptional Items	**0.0**	**1,568.8**
Total	**1,491.3**	**3,166.2**

There are a number of points to note regarding the review of the TSO's PR5 opex. This Final Determination paper focuses on changes or key points of note since Draft Determination. For further detail please see the PR6 Transmission Draft Determination (CRU202588) and PR5 and PR6 TSO Opex Cost Assessment (CRU2025203) published alongside this paper.

2.2.1.1. TAO Payment

This category refers to monies recovered by the TSO and paid to the TAO.

Draft Determination

This was included in the Draft Determination proposal as a non-controllable opex outturn cost totalling €1,510.4m.

Summary of Responses

The TSO expressed concern regarding the inclusion of the TAO Payment in its PR5 outturn spend. The TSO stated that these monies are recovered by the TSO and paid to the TAO, that this is a set part of the regulatory framework prescribed in the Infrastructure Agreement, and that presenting this as an overspend compared to its PR5 allowance, as was the case in the PR6 Draft Determination, was misleading to industry and customers.

Final Determination

The CRU agrees with the viewpoint of the TSO and has subsequently removed the TAO Payment from the presentation of PR5 outturn costs throughout this Final Determination paper. They have also been removed from the presentation of PR6 allowances.

2.2.1.2. PSO Levy

The PSO is a levy applied to all final electricity consumers in Ireland, used to fund government schemes supporting the construction and operation of renewable electricity sources.

Draft Determination

This was included in the Draft Determination proposal as a non-controllable opex outturn cost totalling €1,690.4m.

Summary of Responses

Similarly to the TAO Payment, the TSO expressed concern to the inclusion of the PSO Levy in the presentation of PR5 outturn costs. The TSO argued that the PSO Levy is not in the scope of TUoS revenues and has not had an allowance or outturn set for it in any previous Price Review, therefore it should not be included in the presentation of costs or allowances.

Final Determination

The CRU agrees with the viewpoint of the TSO and has subsequently removed the PSO Levy from the presentation of PR5 outturn costs throughout this Final Determination paper. They have also been removed from the presentation of PR6 allowances.

2.2.2. Review of TAO Operational Expenditure

The TAO's expected opex outturn for PR5 is €374.9m and is set out in Table 13. There is an expected overspend of €14.2m (7%) in controllable opex costs.

Table 13: TAO PR5 Expenditure

PR5 Costs	*Ex-ante* Allowance (€m)	Actual / Forecast (€m)
Transmission Operations	11.7	17.3
Planned Maintenance	109.9	109.4
Fault Maintenance	13.5	12.7
Transmission Retirements	-	-0.04
Asset Management[14]	2.9	4.2
Company Wide Costs	21.4[15]	2.4
Corporate Charges		22.2
Insurance	3.8	4.4
Legal	1.3	-
Pension	2.4	2.1
IT Opex[16]	-	-
Professional Fees	15.0	13.7
Telecom Fees	10.5	9.2
Total Controllable	**192.5**	**197.6**
Network Rates	190.7	165.1
CRU Levy	6.6	12.3
Total Non-Controllable	**197.3**	**177.3**
Total	**389.9**	**374.9**

In contrast to the controllable opex, the TAO forecasts total non-controllable opex of €177.3m compared to an allowance of €197.3m, mostly as a result of lower than anticipated Network Rates, which have a forecasted outturn that is €25.1m or 13.4% less than the PR5 allowance.

This Final Determination paper focuses on changes or key points of note since Draft Determination. For further detail please see the PR6 Transmission Draft Determination (CRU202588) and the PR5 and PR6 TAO Opex Cost Assessment (CRU2025204) published alongside this paper. There is one point to note regarding the review of the TAO's PR5 opex.

[14] This cost category was referred to as 'Wayleaves' during PR5.
[15] Both of these costs were included under the 'Corporate Costs' category in PR5 Final Determination. Since these costs were assessed collectively, individual allowance values for each are not available.
[16] This is a newly requested cost category for PR6, under which no costs were incurred or allowed for PR5.

2.2.2.1. Miscellaneous

Draft Determination

As footnoted in CRU202588, during the quality assurance process prior to Draft Determination publication, the TAO clarified that Miscellaneous costs of €9.1m were included for information purposes as opposed to for seeking an *ex-post* allowance. The CRU committed to reflecting this in the Final Determination.

Summary of Responses

Regarding Miscellaneous costs, the TAO again stated that these costs were included with ESB Networks' business plan questionnaire (BPQ) submission to enable reconciliation with ESB Networks' published accounts and are not relevant for regulatory allowance setting purposes. These costs are primarily driven by accounting adjustments and do not represent costs which the TAO is seeking funding for as part of the PR5 outturn/PR6 submission. The TAO requested that the Final Determination is updated to reflect this position.

Final Determination

The CRU accepts the position of the TAO, i.e. that they are not seeking an allowance for these costs and therefore the CRU is not assessing whether the outturn is efficient. These costs were however allowed for in the 2025/26 revenue and tariff setting process, and will thus need to be adjusted for as part of the 2026/27 tariff setting process.

2.3. Conclusions

Overall, in PR5 the total TSO and TAO opex allowed outturn was €3,166.2m and €374.9m, respectively, against the PR5 allowed expenditure of €1,491.3m and €389.9m, respectively. There was a 112% increase and 4% decrease in the TSO and TAO opex outturn, respectively.

The TSO and TAO capex outturn was €347.8m and €1,185.0m against the PR5 allowances of €280.9m and €1,302.7m[17], respectively. The CRU notes the following:

- The TSO overspend for opex is primarily driven by Exceptional Items, namely Security of Supply (€1,314.0m).

[17] This figure represents project related network capex and excludes adjustments including TAO Adjustment, Interest During Construction, Protection, Telecoms and Station Security, and Customer Contributions.

- The TSO overspend for capex was driven by in-period adjustments for non-network capex projects.
- The TAO underspend was driven in-part by an under-delivery of overhead lines.

3. Review of Forecast Expenditure 2026 – 2030

This part of the paper sets out the CRU's Final Determination on the TSO and TAO's allowed expenditure for PR6 (2026 – 2030). The following sections will summarise the:

- Review of Forecast Capital Expenditure; and
- Review of Forecast Operational Expenditure.

The objective of the review of forecast expenditure is to set the transmission allowances at an efficient level that allows the TSO and TAO to carry out their functions and to ensure consumer interest is protected. In addition, given the transformational change that is expected over PR6 and beyond, the CRU has also considered step changes and new activities that may be required from the TSO and TAO in order deliver transformational change and climate action targets. The submitted cost requests are reviewed based on the need for, additionality and cost efficiency of the step change:

1. **Need:** Is there clear evidence that there is expected to be a change in the activities or costs incurred by the network company and has the change been clearly mapped to the BPQ?
2. **Additionality:** Has it been clearly demonstrated that the costs associated with the step-change are additional relative to the base level?
3. **Cost Efficiency:** Has it been clearly demonstrated that the costs associated with the step-change are efficient? Have other options been explored that could achieve the same outcome? What metrics have been used to test that the requested costs are efficient?

It should be noted that TAO put forward a factored baseline capex proposal, which is presented in its submission on an annual basis. This figure has been put forward to account for uncertainty related to external factors (customer requirements, external dependencies, etc), as well as constraints on delivery of the full programme. In addition to the baseline, the TAO has put forward additional costs required to deliver against the 2030 targets and objectives. This corresponds to the 'high' cost forecast for PR6.

For further detail please see the PR5 and PR6 TSO Opex Cost Assessment (CRU2025203), PR5 and PR6 TAO Opex Cost Assessment (CRU2025204) and Review of TSO and TAO Capex PR5 and PR6 (CRU2025206) published alongside this paper.

3.1. Forecast Capital Expenditure

This section sets out the CRU's Final Determination in relation to the TSO and TAO capex for PR6. As with PR5, where it is not possible for the network companies, at the beginning of the period, to provide sufficiently detailed forecasts/evidence of the projects that will be undertaken during the period, a full allowance will not be provided *ex-ante*. However, the CRU recognises the potential for changing requirements within the PR6 period and has considered how best to progress projects/initiatives through uncertainty mechanisms.

Table 14 below summarises the baseline request[18], high request, the CRU's Final Determination and the variance from the Draft Determination proposal. As stated above, the high allowance represents the additional expenditure that can be sought through the CRU's AIMF for PR6 (see Review of TSO and TAO Capex PR5 and PR6 (CRU2025206)). The breakdown of allowances is also set out in Appendix 1.

Table 14: Summary of Capital Expenditure over the PR6 period (2026 – 2030)

Category	PR6 Request (€m)		Final Determination (€m)		DD – FD Variance	
	Baseline	High	Baseline	High	Baseline	High
TSO Network Capex	286.5	286.5	247.4	286.5	+23.9	+23.9
TSO Non-Network Capex	590.6	590.6	469.5	569.6	+33.5	-5.4
Total TSO Capex	**877.1**	**877.1**	**716.9**	**856.1**	**+57.4**	**+18.5**
TAO Network Capex[19]	3,383.8	5,655.2	3,009.5	5,655.2	-1,007.5	-20.3
TAO Non-Network Capex	29.0	29.0	6.5	29.0	+6.5	+29.0
Total TAO Capex (Gross)	**3,412.8**	**5,684.2[20]**	**3,016.0**	**5,684.2**	**-1,001.0**	**+8.7**
Interest During Construction	-	-	-	-	-	-
Customer Contributions	-140.0	-340.0	-140.0	-340.0	+0.0	-142.0
Total Transmission Capex (Net of Contributions)	**4,149.9**	**6,221.3**	**3,592.9**	**6,200.3**	**-943.6**	**-114.8**

[18] The requested capex has been updated to reflect the Integrated ITP Baseline 1.
[19] TAO network capex exclusive of TSO network capex invoiced to the TAO.
[20] Note that the baseline forecast costs exceed the high case for CP0816 and CP1216. In these cases, the baseline value has been taken as the high case for consistency.

Please note that all costs set out in the review of forecast capex are in 2024 prices.

As noted above, the TSO/TAO network capex submission included two scenarios, a baseline scenario and a baseline plus AIMF scenario. Updated information has been submitted by the TSO/TAO in September and November 2025, which is described as the Integrated Transmission Programme Baseline 1' (ITP B1). Details of this are provided in Section 3.1.1.1.

In ITP B1, the TSO and TAO requested €3.7 billion across 381 projects under its baseline scenario, with a view to potentially unlock the funding for the additional forecast costs of €2.3 billion during PR6 via the AIMF. However, review of the updated information alongside the 369 projects identified in the original BP submission resulted in identification of a total of 526 projects, reflecting substantial changes to the project list. More details are provided in section 3.1.1 and subsequent sections.

It should be noted that, as in the BPQ, the updated requested allowance for the TSO is the same under both the baseline and high scenario (€286.5m) as the early-stage project planning activities undertaken by TSO will be required regardless of the speed of asset delivery by the TAO.

Following a review of the TSO and TAO submissions, the CRU is allowing a gross capex baseline allowance of €3,732.9m (including network and non-network capex). This corresponds to a net capex baseline allowance of €3,592.9m. This is a 134% increase in the gross capex allowance compared with PR5 outturn. The CRU is also providing access to an additional €2,807.4m (excluding customer contributions) through the AIMF.

3.1.1. Review of Forecast Network Capital Expenditure

Review of the updated information in relation to the TSO and TAO's capex request has identified a total of 526 projects, building on details provided in the original business plan submission for 369 projects. Further detail is provided about the additional information that has been received since the Draft Determination consultation in Section 3.1.1.1. The projects are split across the five groups identified at Draft Determination (based on project categories determined the TSO/TAO). The project categories are defined in Table 15 below.

Table 15: Description of PR6 Onshore Capex Categories

Category	Description
1	Large key priority projects, system reinforcements, refurbishments and uprate projects which provide most of the forecasted expenditure and additional network capacity in the submitted plans.
2	Existing contracted renewable energy from previous renewable schemes and auctions such as RESS, ECP 2.1, ECP 2.2, and ECP 2.3. This category includes a mix of solar, wind, batteries and new technology projects.
3	The required system reinforcement projects to facilitate delivery of the 6 ORESS1 connection projects, to minimise constraints and improve the efficiency of the system.
4	Delivery of transmission DSO connected demand and large demand customers.
5	A large number of projects which will delivery significantly less additional renewables and capacity and therefore equates to a minority of the forecasted investment expenditure.
6	Various refurbishment projects such as replacement of overhead line conductors and transformers, station refurbishments and fibre wrapping.
7	System reinforcement and system operator preferred connection method projects such as Renewable Hubs and additional future reinforcements and capacity for renewable projects.
8	Future renewable projects not included in Category 2 including solar, battery storage and wind under ECP 2.3 and ECP 2.4.

3.1.1.1. Integrated Transmission Programme Baseline 1

The TSO/TAO provided submissions to the CRU in relation to the ITP B1 plan in September 2025 and November 2025, which are stated to reflect the most accurate programme information and requested to be used as the basis for delivery tracking.

The network companies have indicated that the PR6 ITP B1 programme, developed jointly by the TSO and TAO, is intended to form the basis for capital investment in PR6 and represents a significant step toward establishing an agreed multi-year transmission programme. They have also requested that the allowances set out in their consultation responses on 11 September 2025 be allocated in full to fund the PR6 Baseline One programme and reflected in the PR6 Final Determination to enable delivery of the required investment and outputs.

The impact of the ITP B1 request at a project group level, when compared with the original Business Plan request, is presented in Table 16.

Table 16: Summary of ITP B1 Request compared with the original Business Plan

Group	Description	PR6 ITP Baseline Request[21] (€m)	vs Business Plan Baseline Request (€m)	PR6 ITP High Request (€m)	vs Business Plan High Request (€m)
TSO					
Group 1	**29 Priority Projects**	140.1	+23.9	140.1	+23.9
Group 2	**Remaining category 1**	11.3	-	11.3	-
Group 3	**Category 2, 4 & remaining category 5**	44.0	-	44.0	-
Group 4	**Category 3**	13.2	-	13.2	-
Group 5	**Category 6, 7 & 8**	77.9	-	77.9	-
Total – TSO		**286.5**	**+23.9**	**286.5**	**+23.9**
TAO					
Group 1	**29 Priority Projects**	2,012.6	+153.8	2,943.2	+0.7
Group 2	**Remaining category 1**	152.5	-	428.2	+0.1
Group 3	**Category 2, 4 & remaining category 5**	888.3	+87.5	1,571.0	-
Group 4	**Category 3**	66.9	-	133.6	-
Group 5	**Category 6, 7 & 8**	263.5	-	576.3	-23.9
Total – TAO		**3,383.7**	**+241.3**	**5,652.3**	**-23.1**
Total – TSO & TAO		**3,670.2**	**+265.2**	**5,938.8**	**+0.8**

Table 16 shows that, in aggregate, there is a change to the high case capex forecast, with apparent reallocation of approximately €24m of capex from TAO to TSO. In the case of the baseline forecast capex, increases are observed in TAO costs for projects in Group 1 and Group 3. This appears to be reasonable in line with changes in project schedules under ITP B1, which reflect improved certainty and maturity, and explanations provided in the consultation response.

In a joint presentation to the CRU and its advisors on 1 October 2025, the TSO and TAO explained that the original approach to estimating factored baseline costs in the BPQ, which involved quantitative risk assessment (QRA) based on project risks such as maturity and outage likelihood, was not adopted in the Draft Determination. As a result, the updated submission bases costs on ITP B1 schedule milestones without QRA adjustments. They also noted that the

[21] The requested capex has been updated to reflect the ITP Baseline 1.

main change from B0 to B1 is that costs now reflect updated project schedule dates and cost profiles. The submissions to the CRU comprised the following information:

- **September:** updates to the baseline and high case forecast capex and details for an expanded range of milestone dates and outcomes at the project level for the 29 priority projects[22], as well as updates to the forecast capex at the aggregate level for each of Groups 2-4.

- **November:** additional updates to expanded range of milestone dates for individual projects under each of the Groups 1-5[23], as well as expanded details of the outcomes associated with these projects[24]. No further update or disaggregation has been provided of the forecast costs for Groups 2-5.

The CRU's advisors undertook analysis of the ITP submissions, primarily through comparative assessment against the original BPQ submitted in 2024. The scope of this analysis was materially constrained by the format of the ITP. Unlike the BPQ, projects were no longer categorised, and the majority of ITP costs were not disaggregated to a project level. These omissions reduced transparency and limited our advisors' ability to undertake a robust assessment.

Following the outcome of this review, the CRU also has concerns that the composition of projects within each group has changed significantly compared to the original business plan submission. The earlier indication from the TSO/TAO that changes between B0 and B1 were limited to updated schedule dates and cost profiles does not fully reflect the extent of variation observed. The key differences are summarised as follows:

- **Group 1:** no change to list of projects identified.

- **Group 2:** of the 35 projects in the original BPQ submission, 23 projects have been moved to Group 5 or removed from the ITP Baseline 1 plan (reduction from 35 to 12 projects).

[22] Including addition of details for the 'initial EI' milestone and 'Capacity Addition (MVA)' outcome.
[23] Including addition of 'CPP accepted' and 'construction start' milestone details for the priority projects and population of the 'initial EI' milestone for the projects under Groups 2-4.
[24] Expanded outcomes include details of 'MVA', 'MEC (MW)', 'OHL New (km)', 'OHL Uprate (km)', 'UGC New (km)', 'Transformers' and 'Stations'.

- **Group 3:** of the 157 projects in the original BPQ submission, 41 have been moved to Group 5 or removed. In addition, 79 projects have been promoted from Group 5 or are newly added in ITP Baseline 1 (increase from 157 to 195 projects).
- **Group 4:** of the 10 projects in the original BPQ submission, 9 have been moved to Group 5 or removed. In addition, 1 project has been newly added in ITP Baseline 1 (reduction from 10 to 2 projects).
- **Group 5:** of the 138 projects in the original BPQ submission, 10 have been moved to Group 3 and 98 have been removed. In addition, 107 projects have been demoted from Groups 2-4 or are newly added in ITP Baseline 1 (decrease from 138 to 137 projects).

Further details of our assessment are provided in Sections 3.1.1.2 and 3.1.1.3 for the TSO and TAO, respectively.

3.1.1.2. TSO Network Capital Expenditure

As set out in Section 3.1, the TSO has proposed both a baseline and high scenario, although the requested allowance for the TSO is the same under both scenarios. The total network expenditure requested by the TSO, the Final Determination and variance from the Draft Determination proposal are set out in Table 17.

Table 17: PR6 TSO Network Capital Expenditure Request, CRU Final Determination

TSO Capex (€m 2024 prices)	PR6 Baseline Request[25] (€m)	PR6 High Request (€m)	FD Baseline (€m)	FD High (€m)	DD – FD Baseline Variance (€m)	DD – FD High Variance (€m)
TSO Network Capital Expenditure Total	286.5	286.5	247.4	286.5	+23.9	+23.9

Following a review of the TSO's submissions, a number of points are noted:

Draft Determination

The following points were noted as part of the CRU's Draft Determination.

- 44% of the request was for 29 priority projects identified by the TSO as priority projects, 26 of which are Category 1 projects. The majority of these have been ongoing or in planning for some time and consequently the project investment need and alternative

[25] The requested capex has been updated to reflect the ITP Baseline 1.

options have been reviewed as part of previous TSO price reviews. The list of 29 includes the 4 projects which constitute EirGrid's Powering Up Dublin plan, which will strengthen electricity infrastructure in Dublin and the surrounding areas.

The CRU proposed to allow the full requested TSO PR6 capex allowance for the key 29 priority projects given the strategic importance of these projects, and reasonable material presented concerning capex cost, delivery timeline, key project risks and the solution development evolution for each project. Additionally, a bundled DO was proposed to be imposed for progression of these projects (see Review of TSO and TAO Capex PR5 and PR6 (CRU2025206)).

- The TSO requested €11.4m for the remaining Category 1 projects. These projects are largely 110/220kV transmission circuit uprates and capacity enhancements and are accompanying elements of the 29 key projects described above. The CRU proposed to allow the full requested TSO PR6 capex allowance for this group of projects given that they are intrinsically linked with the 29 high priority transmission projects and of relatively high importance.

- 157 non-priority projects fell within categories 2, 4 and 5, with a requested allowance of €44.0m. The drivers for these projects are 'Contracted Renewables,' 'Demand' and 'System Reinforcement,' respectively. The CRU proposed to allow the full requested TSO PR6 capex allowance for this group of projects.

- The TSO requested €13.2m for 10 non-priority category 3 (offshore connections) projects. The CRU proposed to allow the full requested TSO PR6 capex allowance for this group of projects.

- The TSO requested €77.9m for 138 of the 369 projects defined as 'early pipeline' projects or 'under consideration' (Categories 6-8 or Group 5). Whilst there is a clear need for a significant proportion of the projects and associated works, at the time of the Draft Determination the TSO's work requirements (stage 1) for the projects was unclear, e.g. planned delivery outputs, costs and timeline. A baseline allowance of €38.9m was proposed for this group. A reopener mechanism was proposed that could be followed by the TSO to allow for additional funding to be released based on justification provided during the period.

Summary of Responses

Table 16 shows that the TSO network capex forecast has increased by €23.9m for Group 1 projects as part of the ITP submissions. The changes are applied to both the baseline and high case forecast capex, consistent with the TSO's original request.

For Groups 1–4, EirGrid welcomes the CRU's allowances at Draft Determination, but expects to use the reopener process later in PR6. Updates will be communicated through ITP and reopener mechanisms.

For Group 5 the TSO supports the CRU's recognition of Group 5 needs but is concerned about the reduced initial funding (€38.9m), which is 50% below the requested high case allowance. This may impact customer connection offers and should be addressed in the Final Determination. Due to early-stage uncertainty, forecasts are based on customer volumes rather than specific projects, but several projects have progressed since the PR6 submission. The TSO points to updated details provided in in ITP B1.

- **Category 6 Refurbishment Pipeline:** 26 early-stage projects focused on equipment replacement and reliability; further details will support full allowance approval.
- **Category 7 Reinforcements & System Operator Preferred Connection Methods (SOPCMs):** SOPCMs (future-proofing measures) are critical for customer offers. Current reliance on reopeners for cost recovery is impractical and risks delays. Five SOPCM projects originally forecast at €3.6m (against two projects) now cost €20m; up to 10 more are expected, making current allowances insufficient.
- **Category 8 Renewables**: 86 early-stage projects included. Recent enduring connection policy (ECP) updates (ECP-2.5, ECP-GSS) accelerate grid access, with 4.5 GW from ECP-2.5 and 86 projects under ECP-GSS-1. Wind Energy Ireland expects 2 GW of new onshore wind in planning within a year. Rising planning approvals support full PR6 allowances for renewables.

Final Determination

As per Section 3.1.1.1, the CRU's advisors undertook analysis of the ITP submissions, primarily through comparative assessment against the original BPQ submitted in 2024. While the scope of the review was limited by the format in which the ITP was presented, the small movements observed in the group costs relative to the BPQ led the CRU and its advisors to be broadly satisfied with the updated costs.

The increase in the forecast costs for Group 1, resulting from the ITP submission, means that the TSO seeks an increase of 100% above its PR5 Outturn (€143.5m to €286.5m) for network capex. €140.1m of the request is for 29 projects identified by the TSO as priority projects. The CRU is allowing the full requested TSO PR6 capex allowance for the key 29 priority projects, in line with ITP B1, given the strategic importance of these projects, and reasonable material presented concerning capex cost, delivery timeline, key project risks and the solution development evolution for each project. The approach to apply a bundled DO for progression of these projects is retained from Draft Determination.

Groups 2, 3 and 4 remain unchanged, with the Final Determination allowance reflecting the full baseline request.

Many projects in Group 5 remain at an early stage with significant uncertainty around the scope, timing, and cost of TSO Stage 1 works. As per the recommendation from GHD (CRU2025206) in view of the changes to the projects identified under the ITP B1 discussed further in Sections 3.1.1.1 and 3.1.1.3, the Final Determination allowance for Group 5 remains at 50% of the requested baseline allowance. The full allowance remains available as part of a reopener.

As noted in the PR6 Draft Determination, in the PR5 Final Determination the CRU requested that the TSO submit more than the three scenarios that it did in PR5 in the PR6 submission. As summarised in Section 3.1, the TSO only submitted two scenarios. The TSO's submission would have benefitted from additional central scenarios to provide a range of plausible PR6 scenarios and better demonstrate the appropriateness of the TSO's preferred scenario. The TSO will need to consider such an approach for PR7.

The TSO's PR6 capex request, Final Determination allowance and variance from the Draft Determination proposal are outlined in Table 18 below.

Table 18: TSO PR6 Capex Request, and Final Determination

	PR6 Total Request[26] (€m)	PR6 FD Baseline Allowance (€m)	DD – FD Variance (€m)
Group 1 – Priority projects	140.0	140.0	+23.9
Group 2 – Remaining Category 1	11.4	11.4	-
Group 3 – Category 2, 4 & remaining Category 5	44.0	44.0	-
Group 4 – Category 3	13.2	13.2	-
Group 5 – Category 6, 7 & 8	77.9	38.8	-
Total TSO Capex	**286.5**	**247.4**	**+23.9**

3.1.1.3. TAO Network Capital Expenditure

The objective of the TAO forecast capex review is to assess the reasonableness of the TAO's proposals to achieve the required outputs during the PR6 period and set appropriate allowances for investment in projects/initiatives. The review of the TAO's capex submission principally considers the total PR6 request, whilst recognising TAO's consideration of deliverability included in the baseline scenario. The total request is summarised in Table 19.

[26] The requested capex has been updated to reflect the ITP Baseline 1.

Table 19: TAO Network Capex Request

TAO Capex (€m 2024 prices)	PR6 Baseline Request[27] (€m)	PR6 High Request (€m)	FD Baseline (€m)	FD High (€m)	DD – FD Baseline Variance (€m)	DD – FD High Variance (€m)
TAO Network Capital Expenditure Total[28]	3,383.8	5,655.2	3,009.5	5,655.2	-1,007.5	-20.3
Interest During Construction Total	-	-	-	-	-	-
Customer Contributions	-140.0	-340.0	-140.0	-340.0	+0.0	-142.0
Total TAO Network Capex Request (Net)	**3,243.8**	**5,315.2**	**2,869.5**	**5,315.2**	**-1,007.5**	**-162.3**

Following the review of the TAO's PR6 submission in relation to network capex, the needs likely to arise over the PR6 period and consideration of consultation responses, a number of points are noted:

Draft Determination

The following points were noted as part of the CRU's Draft Determination.

- In the context of the regulatory framework, the approach to setting allowances was based on the expectation of full delivery of priority projects where possible, in line with delivery plans put forward and allowing for changes during the period based on explanation of the reasons. This approach looked to focus TAO activities and incentivise the delivery of these through careful management of the associated risks, with the view that it would be more appropriate to deliver the full achievable project progress (including addition of network capacity) in critical areas over PR6. To that end, DOs were imposed for Groups 1, 2 and 4 (individual DOs for each priority project in group 1; separate bundled DOs for all of the projects in each Group 2 and 4).

- For Groups 3 and 5, category allowances were recommended with reopeners to allow for additional funding to be released based on justification provided during the period (anticipated to be streamlined, based on demonstration of the ESB Networks internal

[27] The requested capex has been updated to reflect the ITP Baseline 1.
[28] TAO network capex exclusive of TSO network capex invoiced to the TAO.

governance processes, but including demonstration that progressing other non-priority projects can be achieved without impacting on the delivery of priority projects). As such, progress could be made on these remaining projects under the baseline category allowances, with reopeners to flex up the allowances.

- For Group 3, a 25% partial allowance was proposed as there was less clarity to support the specifics of what will be delivered from these projects, and they are (somewhat) less critical to the system needs, so considering the deliverability challenge we deemed it to be appropriate to propose a reduced allowance with the ability to flex up via a reopener. However, it was set out that the expenditure on this group should be considered separate from the ringfenced allowances for the priority projects, as there needs to be transparency related to changes to these.

- For Group 5, a 20% partial allowance was proposed as whilst it was found that there was a need for the projects and associated works within Group 5, it was unclear as to full TAO work requirements. The nature of these projects, including that a number of these are placeholder projects, means a degree of churn and potential replacement, cancellation and revision was expected.

- The 29 key projects (of the 369 projects) in Category 1 formed approximately 52% of total PR6 forecast expenditure in the period. The CRU proposed a full allowance for these projects as the need was sufficiently demonstrated, costs were deemed reasonable, and these projects were seen as critical to allow Ireland to achieve its national and European energy targets. A DO was applied to these projects.

- As noted in Section 3.1, the TAO provided a baseline scenario using factoring weights to reflect its view on the challenges and potential issues associated with project delivery through PR6. Whilst the basis for the factoring approach was broadly understood, given the need for the TAO to deliver transmission infrastructure at pace through PR6 and to obtain clarity of delivered outputs associated with allowances, it was considered more appropriate to focus on full PR6 project costs. Hence, whilst considered in aggregate, the factored costs were not adopted directly for the priority projects.

- It should also be noted that applying DOs on a factored basis would be potentially challenging, as project progress is not necessarily linear with capital spend and, if money is moved across projects due to deliverability issues, this may not necessarily result in equivalent outcomes or benefits, meaning less overall benefit is obtained for customers for the same spend. Retaining transparency and visibility of actual incurred project capital

spend tied to a direct capital allowance was therefore considered an important aspect of the PR6 regulatory framework.

- The TAO requested €428.1m for the remaining Category 1 projects. These projects were largely 110/220kV transmission circuit uprates and capacity enhancements and are accompanying elements of the 29 key projects described above. The CRU proposed a full allowance for these projects under a single bundled DO given that they are intrinsically linked with the 29 high priority transmission projects and of relatively high importance.

- The TAO requested €1,571.0m under Categories 2, 4 and 5 (Group 3). An allowance of 25% (€392.8m) was provided. A category allowance was applied to the 25% and a reopener applied to the remainder of the request to allow for additional funding to be released based on justification provided during the period.

- The TAO is requesting €133.5m under Category 3. The CRU proposed a full allowance under a DO given the importance of these offshore wind development projects in achieving national and European energy targets.

- The TAO requested €600.2m for 138 projects defined as 'early pipeline' or under consideration under Categories 6, 7 and 8 (Group 5). While there was a clear need for a variety of projects and associated works, it was unclear as to the full TAO work requirements. An allowance of 20% (€120.1m) was provided. A reopener mechanism was provided to allow for additional funding to be released based on justification provided during the period.

Summary of Responses

Table 16 shows that the TAO baseline network capex forecast has increased by €153.8m for Group 1 projects and €87.5m for Group 3 projects. The high case capex requirements remain broadly unchanged, with adjustments proposed to be managed through AIMF uncertainty mechanisms.

For Group 1, in addition to the updates to the forecast baseline capex for each individual project in Group 1, updates have been provided to the individual milestone dates (including 'initial Energisation Instruction (EI)', 'Committed Programme Parameter (CPP) accepted' and 'construction start' in addition to the milestones provided in the original BPQ) and outcomes ('MVA', 'Maximum Export Capacity (MEC) (MW)', 'OHL New (km)', 'OHL Uprate (km)', 'UGC New (km)', 'Transformers' and 'Stations'). The key changes observed in relation to the 29 priority projects in Group 1 are summarised as follows:

- Final energisation milestone dates have changed, ranging from being brought forward 12 months to delayed by 34 months (average delay of 3 months).
- Outcomes:
    - 18 projects with MVA capacity specified in the ITP B1 submission, of which 13 have changed by at least 93 MVA compared with the capacity specified in ITP B0 (ranging from a reduction of 786 MVA to an increase of 275 MVA, and an overall reduction of 3,595 MVA across the 13 projects).
    - 5 projects with no MVA capacity, but other outcomes specified in ITP B1.
    - 5 projects with no outcomes specified in the ITP B1, but details of MVA capacity available from ITP B0.
    - 1 project (CP1213 - Belcamp 220 kV Busbar Extension) with no outcomes specified in any of the submissions provided to date.

For Group 2, as indicated in Section 3.1.1.1, of the 35 projects in the original BPQ submission, 9 projects have been moved to Group 5, and 14 projects have been removed from the ITP B1 plan (reduction from 35 to 12 projects).

No details of the forecast costs at an individual project level have been provided (beyond those provided in the original BPQ for the original project list) to reflect the change in the projects listed within the group.

For Group 3 of the 157 projects in the original BPQ submission, 5 have been moved to Group 5 and 36 projects have been removed from the ITP B1 plan. In addition, 10 projects have been promoted from Group 5, 51 projects have been introduced as being carried over from PR5 and 18 projects have been newly added in ITP B1 (increase from 157 to 195 projects).

No details of the forecast costs at an individual project level have been provided (beyond those provided in the original BPQ for the original project list) to reflect the change in the projects listed within the group.

For Group 4, of the 10 projects in the original BPQ submission, 5 have been moved to Group 5 and 4 projects have been removed from the ITP B1 plan. In addition, 1 project has been newly added in ITP B1 (a reduction from 10 to 2 projects).

No details of the forecast costs at an individual project level have been provided (beyond those provided in the original BPQ for the original project list) to reflect the change in the projects listed within the group.

Finally, for Group 5, of the 138 projects in the original BPQ submission, 10 have been moved to Group 3 and 98 have been removed. In addition, 19 projects have been demoted from Groups 2-4, 24 projects have been introduced as being carried over from PR5 and 64 projects are newly added in ITP B1 (decrease from 138 to 137 projects).

No details of the forecast costs at an individual project level have been provided (beyond those provided in the original BPQ for the original project list) to reflect the change in the projects listed within the group.

Final Determination

As per Section 3.1.1.1, the CRU's advisors undertook analysis of the ITP submissions, primarily through comparative assessment against the original BPQ submitted in 2024. While the scope of the review was limited by the format in which the ITP was presented, the small movements observed in the group costs relative to the BPQ led the CRU and its advisors to be broadly satisfied with the updated costs.

Group 1

The CRU acknowledges the updates that have been made to the project delivery schedules and costs, as well as the representations to consider the revised baseline capex forecast from ITP B1 as being the *"single, aligned and realistic delivery baseline for all PR6 transmission investments"*. As such, the CRU provides a baseline capex allowance in line with the forecast baseline capex associated with the Group 1 projects presented in ITP B1 (€2,012.5m).

This baseline capex allowance is provided in conjunction with individual DOs for delivery of each of these important projects, which will make use of the best/latest available information for project milestone dates, capacity additions and other outcomes that are available from ITP B1 (Rev 1 and Rev 0) and the original BPQ submission, as required.

Group 2

The CRU provides a baseline allowance for this group in line with the baseline forecast capex from ITP B1 (€152.5m).

However, the CRU does not consider that the information provided about the constituent projects that make up this group – and the changes to the list of projects – has been adequately explained. As such, the bundled DO associated with this group will consider the original list of 35 projects to be the *ex-ante* baseline at Final Determination.

Group 3

The CRU provides a baseline allowance for this group of €657.4m, which provides an additional baseline allowance compared with Draft Determination to account for the requirement for TAO investment associated with DSO network projects.

However, similar to Group 2, the CRU does not consider that the information provided about the constituent projects that make up this group – and the changes to the list of projects – has been adequately explained. As such, the reopener associated with this group will consider the original list of projects plus the 69 projects that have been added in ITP B1 to be the *ex-ante* baseline at Final Determination (i.e. moves between groups have not been accepted, but additional projects are included for reference in line with the approach to capture the best available information).

Group 4

The CRU provides a baseline allowance for this group in line with the baseline forecast capex from ITP B1 (€66.9m).

The CRU has similar reservations about the information provided about the constituent projects that make up this group – and the changes to the list of projects – which have not been adequately explained. However, the bundled DO associated with this group will consider the two projects identified in ITP B1 to be the *ex-ante* baseline at Final Determination since it is deemed that it is reasonable that this reflects the interaction with the offshore connections activity.

Group 5

The CRU provides a baseline allowance for this group of €120.1m, which is unchanged from the Draft Determination position.

However, similar to Groups 2 and 3, the CRU does not consider that the information provided about the constituent projects that make up this group – and the changes to the list of projects – has been adequately explained. As such, the reopener associated with this group will consider the original list of projects plus the 88 projects that have been added in ITP B1 to be the *ex-ante* baseline at Final Determination (i.e. moves between groups have not been accepted, but additional projects are included for reference in line with the approach to capture the best available information).

Summary

The CRU remains satisfied that the TAO has the allowances to deliver the PR6 capex plan, however, it represents a very challenging work programme that requires a significant step up in resourcing, planning and coordination across the business (as well as with the TSO). The TAO

will need to introduce and focus on flexible and innovative development and delivery approaches to deliver projects in a timely manner.

The TAO's PR6 capex request, CRU's Final Determination allowance[29] and the variance from the Draft Determination proposal are outlined in Table 20 below.

Table 20: TAO PR6 Capex Request and Final Determination[30]

	PR6 Total Request (€m)	PR6 FD Baseline Allowance (€m)	PR6 FD High Allowance (€m)	DD – FD Baseline Variance (€m)	DD – FD High Variance (€m)
Group 1 – Priority projects	2,946.2	2,012.5	2,946.2	-930.0	+3.7
Group 2 – Remaining Category 1	428.2	152.5	428.2	-275.7	-
Group 3 – Category 2, 4 & remaining category 5	1,571.0	657.4	1,571.0	+264.7	-
Group 4 – Category 3	133.5	66.9	133.5	-66.6	-
Group 5 – Category 6, 7 & 8	576.4	120.1	576.4	-	-23.8
Total TAO Capex	**5,655.3**	**3,009.4**	**5,655.3**	**-1,007.5**	**-20.1**

3.1.2. Non-Network Capital Expenditure

The following subsections summarises the CRU's review of TSO and TAO non-network Final Determination for PR6.

3.1.2.1. TSO Non-Network Capital Expenditure

The total non-network capex requested by the TSO for the PR6 period is summarised in Table 21 below.

[29] A reopener covering Groups 1, 2 and 4 is also applicable. It can be triggered annually, if the overall costs are forecast to exceed the total baseline allowance. See Review of TSO and TAO Capex PR5 and PR6 (CRU202599d) for further detail.
[30] TAO network capex exclusive of TSO network capex invoiced to the TAO.

Table 21: TSO PR6 Non-Network Capex Request

Cost Items	PR6 Request (€m)
TSO Transformation	133.7
Technology Resilience and Modernisation	101.0
Power System Capability Enhancement	90.2
Digital Transformation	49.2
Celtic Operational Readiness	32.0
Physical Control Centres	23.4
Cyber Security	13.3
TSO/DSO Coordination	11.2
Workplace/Facilities Capex	5.4
Capability Catchup	4.1
FASS	18.2
SMP	89.3
Market System Release Capital	19.6
Non-Network Capital Expenditure Total	**590.6**

Following a review of the TSO's submissions and consultation responses, are number of points are noted:

3.1.2.1.1. TSO Transformation

This programme is targeted at building the TSO's capacity and capability to adjust the system to support the movement towards decarbonised power systems. It encompasses a broad range of initiatives to facilitate a successful transition to a low-carbon energy future.

Draft Determination

The TSO requested €133.7m under this cost category. Based on the assessment at Draft Determination, the need for the subprogrammes was generally demonstrated, albeit it was judged that there was some uncertainty around specific outputs and demonstration of efficient costs. The CRU proposed a baseline allowance of €65.9m, alongside a reopener to enable additional funding to be released should this be justified during the PR6 period.

Condition 42 of SONI Licence

Condition 42 requires SONI makes *provision for the effective corporate governance and management of the Licensee in the interests of consumers*. Licence Condition 42 also offers SONI the ability to derogate from requirements. EirGrid requested €21m under this subcategory.

During the CRU's quality assurance process prior to Draft Determination publication, it was identified that an allowance of €4.2m for costs associated with Condition 42 of SONI Licence was included in error. The CRU proposed not to allow this as part of Final Determination.

Summary of Responses

EirGrid has accepted the CRU's Draft Determination baselines for certain projects, such as Long Duration Energy Storage (LDES) and Capacity Remuneration Mechanism (CRM) post-2027, provided a reopener mechanism is available for future funding. However, EirGrid sought a higher baseline allowance for items where a 20% cost reduction was applied, arguing that full funding is necessary to deliver critical capabilities. For Development Operations, EirGrid contends that €2.2m is justified for essential software and testing tools, while for Enduring Operational Transformation, it maintains that €3.8m is needed for enterprise-grade project management software to support PR6 investment scale. EirGrid also requests reconsideration of seed funding, stating it plays a unique role in bridging gaps before CRU approval and proposes a reduced "use-it-or-lose-it" arrangement.

Condition 42 of SONI Licence

The TSO cited the following sections of the Act which they state *"requires the following of the CRU regarding financing activities":*

9(4)(c): *"The Commission shall have regard to the need to secure that licence holders are capable of financing the undertaking of the activities which they are licensed to undertake"*

and

9BC(2)(b): *"the Commission shall carry out their respective functions referred to in subsection (1) in the manner which each considers is best calculated to further the principal objective, having regard to the need to secure that authorised persons are able to finance the activities which are the subject of conditions or obligations imposed by or under this Act or the Internal Market Regulations or any corresponding provision of the law of Northern Ireland".*

The specific subsection referred to by the TSO (9BC(1)(b)) states that: *"The principal objective of the Commission in giving effect to any decision of the SEM Committee is to protect the interests of consumers of electricity in the State and Northern Ireland supplied by authorised persons, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the sale or purchase of electricity through the Single Electricity Market."*

The TSO also cited Condition 1(9) Interpretation and Construction of the TSO Licence which states:

"9). Where any Condition of this Licence requires the Licensee to act "in conjunction with the Northern Ireland System Operator" in the fulfilment of an obligation, the Licensee shall:

a) *to the extent the Licensee is reasonably capable of fulfilling that obligation without the assistance of the Northern Ireland System Operator, be obliged to fulfil that obligation and shall use all reasonable endeavours to work together with the Northern Ireland System Operator in so doing;*

b) *to the extent the Licensee is not reasonably capable of fulfilling that obligation without the assistance of the Northern Ireland System Operator:*

    i. *ensure that the System Operator Agreement requires the Northern Ireland System Operator to provide the assistance in question, and, where it does not, seek to amend the System Operator Agreement so that it does;*

    ii. *exercise all rights available to the Licensee (including under the System Operator Agreement) in order to obtain the assistance in question; and*

    iii. *on obtaining the assistance in question, be obliged to fulfil that obligation and shall use all reasonable endeavours to work together with the Northern Ireland System Operator in so doing.*

c) *to the extent the Northern Ireland System Operator is obliged (by the laws or licence obligations applicable to it) to act in conjunction with the Licensee in the fulfilment of an equivalent obligation, be obliged to provide such assistance as the Northern Ireland System Operator reasonably requests in order to enable it to fulfil that obligation."*

EirGrid contend that the CRU's position would appear to run counter to this obligation and could imply that *"where EirGrid, acting in compliance with its statutory functions, efficiently incurs costs in fulfilling any obligation itself that such costs may not be provided for, should the CRU hold a view that further efficiency is or may have been attainable though shared arrangements with SONI notwithstanding that such an arrangement would not be in keeping with the above licence objectives."*

Final Determination

The assessment remains broadly unchanged after reviewing the additional information provided since the Draft Determination. While the TSO's documentation reinforces the case for the initiative, some uncertainty persists around outputs and cost efficiency, so the CRU maintains the

view that a reduced allowance for eight of the line items is appropriate. CRU support full funding for the Outage Transformation initiative and other items related to surveys, studies, and innovation, with an *ex-post* review planned to assess efficiency.

For Seed Funding, CRU maintain that this should be treated as a placeholder under AIMF, with no initial allowance, but the TSO may return during the period with robust business cases for specific capital funding.

Condition 42 of SONI Licence

The CRU has reviewed the sections and conditions cited by the TSO. Provisions such as Section 9BC(2) and Condition 1(9) are not relevant to funding decisions, as they relate to cooperation between system operators rather than cost recovery. The CRU's obligation to have regard to the need to secure EirGrid is capable of financing its licensed activities is limited to the activities set out in its licence. The costs associated with EirGrid's chosen approach arise from independent decisions taken by EirGrid and SONI. These costs do not deliver efficiencies or benefits to Irish electricity customers.

Accordingly, the CRU's position remains unchanged from the Draft Determination: no PR6 ex-ante allowance will be provided under SONI Licence Condition 42 request.

3.1.2.1.2. Technology Resilience and Modernisation

A programme which seeks to invest in the TSO's IT infrastructure for grid management. Maintenance of a reliable, up-to-date system mitigates the risk of an outage causing any significant shortages of supply, underpins the TSO's functions and enables other PR6 initiatives such as Power System Capability Enhancement, TSO/DSO Coordination, Digital Transformation and Physical Control Centres.

Draft Determination

The TSO requested €100.9m under this cost category. The CRU requested additional information in relation to four subprogrammes where a lower level of detail was provided to support the requested capex allowance. This resulted in a proposed baseline allowance of €94m.

Summary of Responses

EirGrid welcomed the proposal to grant full allowances for four key line items: Essential Application Modernisation & Change, Architecture & Integration, Service Transformation, and Telecommunications.

The largest item under review was Hardware & Software, where an 80% allowance was proposed. EirGrid provided additional cost breakdowns to address uncertainties raised. This further detail was intended to support recognition of the full allowance across Technology Resilience and Modernisation.

Final Determination

The CRU considers it appropriate to grant full capex allowances for the four initiatives that provided sufficient detail on need, outcomes, options, and cost evidence in the PR6 submission. For the remaining items, ongoing uncertainties around cost sources and references justify an 80% allowance, which will be reviewed at the end of PR6 as part of the *ex-post* review process.

3.1.2.1.3. Power System Capability Enhancement

A project aimed at delivering the capabilities required to operate the power system in a secure and resilient manner as higher levels of non-synchronous renewable generation is accommodated.

Draft Determination

The TSO requested €90.2m under this cost category. It was assessed that the overall need for the subprogrammes was reasonably clearly demonstrated, in many cases related to RES-E and 2030 energy targets. However, it was also judged that there was an absence of a more detailed and bespoke optioneering assessment for substantial initiatives within this category, and a lack of clarity about the basis for capex cost estimates. The CRU proposed a baseline allowance of €45.3m, to be provided in conjunction with a reopener mechanism (single mechanism covering TSO non-network costs).

Summary of Responses

EirGrid views Power System Capability Enhancement as critical for managing a more complex power system and meeting energy targets. While open to a reopener for later years, EirGrid argued that the proposed 50% funding is too low for near-term needs and risks delaying essential capabilities. EirGrid requested a higher baseline for early PR6 years and warned that underfunding could increase system-security risks, operational costs, and consumer impacts.

Final Determination

The CRU agrees with GHD that earlier concerns around optioneering and cost estimation have been partly addressed. Consequently, CRU considers it appropriate to increase the allowance from €45.3m to €63.3m, up €18m or 39.7% from Draft Determination, granting full funding for Energy Management System (EMS) Modernisation and Future Dispatch. This uplift reflects

greater confidence in the scope and justification of these investments, while remaining uncertainties will be managed through the reopener mechanism during PR6.

3.1.2.1.4. Digital Transformation

The TSO described this programme as one that will *"support meeting regulatory objectives by focusing on enhancing network efficiency, reliability, and sustainability through digital transformation."* The TSO stated that the programme focuses on transforming its IT systems that support its *"customers, stakeholders, workplace, human capital management, and overall data capability."*

Draft Determination

The TSO requested €49.2m under this cost category. The overall need for the subprogrammes was reasonably clearly demonstrated. However, there was an absence of a more detailed and bespoke optioneering assessment for substantial initiatives within this category, and a lack of clarity about the exact outputs and outcomes to be provided. The CRU proposed baseline allowance of €24.8m, which was be provided in conjunction with a reopener mechanism.

Summary of Responses

EirGrid set out that its Digital Transformation programme is positioned as a core investment to modernise systems, enhance efficiency, and support the energy transition. It spans data strategy, analytics, digital workplace, and enterprise systems, aiming to improve compliance, agility, and operational performance. EirGrid has provided optioneering assessments for each area, generally favouring solutions that build on existing enterprise platforms to reduce delivery risk and maximise integration. Overall, the programme is presented as essential for system reliability, statutory compliance, and delivering consumer value in a rapidly evolving energy environment.

Final Determination

After reassessing business cases and EirGrid's Draft Determination response, the CRU acknowledges that several concerns, particularly around cost breakdowns and overall justification, have been addressed. While optioneering and cost estimation remain high-level for larger items, improved clarity supports revising the recommendation from 50% to 80% of the requested value e.g. €39.3m. This uplift reflects greater confidence in the programme while allowing further refinement through the reopener mechanism during PR6.

3.1.2.1.5. Celtic Operational Readiness

A strategic initiative aimed at ensuring the integration from the construction phase to the operational phase of the Celtic Interconnector into the TSO's systems.

Draft Determination

The TSO requested €32.0m under this cost category. The Draft Determination assessment judged that need for the works was clear, with the cost request being split into capex costs associated with labour and resourcing and separately for IT Systems. However, there was uncertainty in the resourcing element of the requested allowance, resulting in a proposed baseline allowance of €28.9m.

Summary of Responses

EirGrid supported the Draft Determination position, noting the work is already underway and costs are well understood.

Final Determination

The CRU has retained its Draft Determination position on the baseline allowance but have expanded the TSO non-network reopener to include Celtic Operational Readiness, resulting in a small uplift to the Final Determination high allowance.

3.1.2.1.6. Cyber Security

A programme of works to build on the foundation delivered in PR5 to address and combat the growing cybersecurity threats and meet statutory and regulatory requirements. This includes compliance with relevant EU directives and delegated acts, most notably the Network Code on Cybersecurity (NCCS) and the NIS 2 Directive, aligning with international standards and maintain up-to-date infrastructure and subject matter expertise.

Draft Determination

The TSO requested €13.3m under this cost category. The need for the works and expenditure was understood, with specific requirements and legislation to be fulfilled. However, there were limitations in the demonstrated optioneering for the works. This resulted in a proposed baseline allowance of €10.4m.

Summary of Responses

EirGrid seeks the full €13.3m cybersecurity allowance, citing expanded regulatory obligations, critical gaps identified in a recent maturity assessment, and the need for scalable SaaS solutions.

EirGrid argue reduced funding would undermine resilience and flexibility to address emerging risks, including AI-related threats, and stress that upfront investment is more cost-effective than breach recovery. Full capex provision is requested, with any opex adjustments managed through AIMF.

Final Determination

With reference to compliance obligations under NIS2 and the new cybersecurity network code, the CRU is increasing its recommended allowance from €10.6m to €13.3m, up €2.7m or 25.4% from Draft Determination. This uplift reflects a clearer understanding of the scope and urgency of the proposed activities and strengthened justification in the updated submission.

3.1.2.1.7. TSO/DSO Coordination

As stated in the PR6 Strategy Paper, the TSO and DSO must adopt a whole-of-system approach as this can minimise costs to customers, improve system efficiency and support the delivery of infrastructure at pace.

Draft Determination

The TSO requested €11.1m under this cost category. The need for the works and expenditure was understood, with specific requirements and legislation to be fulfilled. The optioneering comparison presented was limited, with no real defined benefits or alternatives presented. Supporting details for the cost build were provided, although the requirement for the specific outlined FTE number was also not supported. As a result, the CRU proposed a baseline allowance of €8.7m.

Summary of Responses

EirGrid said it has chosen a coordination model based on the ENA Open Networks Project and stresses flexibility to meet evolving requirements. They request the full allowance and support a reopener mechanism due to potential cost increases and external dependencies.

Final Determination

CRU's view remains that, while the need for the works and associated expenditure is clear and supported by specific requirements and legislative obligations, the optioneering analysis continues to be limited, with no clearly defined benefits or alternative options presented.

3.1.2.2. TSO Non-Network Final Determination Summary

As set out in Table 21, a total of 13 projects representing €590.6m are included in the TSO's non-network capex submission.

To summarise, 79% of requested non-network allowances have been included within the baseline allowance this Final Determination (see Table 23). The allowance of €469.5m for PR6 represents a *circa* 130% increase on PR5 outturn. This Final Determination includes a number of opportunities for the TSO to access additional revenue through reopener mechanisms. More detail on these mechanisms can be found in the Review of TSO and TAO Capex PR5 and PR6 (CRU2025206).

When evaluating the allowances, the CRU focused on the likely need for the projects over the PR6 period that align with the CRU's PR6 objectives and whether the need for, additionality and cost efficiency of each project was sufficiently demonstrated. Changes in expenditure against these allowances will need to be explained and substantiated with evidence at the close of PR6 (i.e. as part of the PR6 *ex-post* review).

3.1.2.3. TAO Non-Network Capital Expenditure

Draft Determination

The TAO made two non-network capex requests, which are summarised in Table 22 below.

Table 22: PR6 TAO Network Capital Expenditure Request, CRU Final Determination and DD – FD Variance

TAO Non-Network Capex Request (€m 2024 prices)	PR6 Request (€m)	FD Baseline (€m)	FD High (€m)	DD – FD Baseline Variance (€m)	DD – FD High Variance (€m)
Distribution Asset Management (Support & Planning)	15.5	0.0	15.5	+0.0	+15.5
Enterprise Applications	13.5	6.5	13.5	+6.5	+13.5
Total	**29.0**	**6.5**	**29.0**	**+6.5**	**+29.0**

Distribution Asset Management: The request relates to statutory Loss of Development payments to landowners, based on agreed national compensation terms and historical forecasts. ESB outlined that these payments cover early goodwill and statutory claims, deducted from future claims, with annual spending assumed over five years.

Enterprise Applications**:** In its response, ESB clarified that TAO's IT needs are distinct from the DSO and critical given PR6 and climate action demands. A high-level roadmap was submitted, highlighting efficiency opportunities through targeted investment and collaboration with the TSO. ESB argues that duplication across TAO and TSO systems could be reduced and that investment would be self-financing over time.

At Draft Determination, no supporting narrative was provided to justify these requests. Additionally, the categories listed are identical to programmes within the DSO submission. Additional information was requested from the TAO in order to support their request.

Summary of Responses

Distribution Asset Management: ESB Networks provided further details on Loss of Development costs, but justification remains unclear. These costs appear to be network development-related and should be managed on a project basis under Network Capex rather than non-network allowances.

Enterprise Applications: While the need for some TAO-specific IT investment is acknowledged, the submission lacks detailed plans, cost estimates, and timelines.

Final Determination

Distribution Asset Management: The CRU recommends no baseline allowance, with flexibility to apply under the TAO non-network reopener if related non-network costs (such as related IT system costs) arise during PR6.

Enterprise Applications: The CRU does not support the full request and has set an initial allowance of 50%, with a reopener mechanism for additional funding upon submission of a robust business case.

3.1.3. Allowed PR6 Capital Expenditure

The CRU's Final Determination on the TSO's network and non-network capex allowances is €247.4m and €469.5m, respectively. This represents a 106% increase over PR5 outturn. The TAO's PR6 baseline network capex allowance is €3,009.5m, an increase of 154% compared to the TAO's PR5 outturn. Table 23 summarises the PR6 Final Determination. A more detailed (annual) breakdown is set out in Appendix 1.

Table 23: PR6 Final Determination

TSO Capex (€m 2024 prices)	PR6 Request (€m)	FD Baseline (€m)	FD High (€m)	DD – FD Baseline Variance (€m)	DD – FD High Variance (€m)
Network Capex	286.5	247.4	286.5	+23.9	+23.9
Network Capex Total	**286.5**	**247.4**	**286.5**	**+23.9**	**+23.9**
TSO Transformation	133.7	61.1	112.7	-4.2[31]	-21.0
Technology Resilience and Modernisation	101.0	94.0	101.0	-	+7.0
Power System Capability Enhancement	90.2	63.3	90.2	+18.3	-
Digital Transformation	49.2	39.3	49.2	+14.4	-
Celtic Operational Readiness	32.0	28.9	32.0	-	+3.1
Physical Control Centres	23.5	23.5	23.5	-	-
Cyber Security	13.3	13.3	13.3	+2.9	+2.9
TSO/DSO Coordination	11.2	8.7	11.2	-	+2.5
Workplace/Facilities Capex	5.3	5.4	5.4	-	-
Capability Catchup	4.1	2.2	4.1	-	-
FASS	18.2	18.2	18.2	-	-
SMP	89.3	89.3	89.3	-	-
Market System Release Capital	19.6	19.6	19.6	-	-
Non-Network Capex Total	**590.4**	**469.5**	**569.6**	**+31.5**	**-5.4**
TSO Total	**876.9**	**716.9**	**856.1**	**+55.4**	**+18.5**
TAO Capex (€m 2024 prices)[32]	**Request (€m)**	**FD Baseline (€m)**	**FD High (€m)**	**DD – FD Baseline Variance (€m)**	**DD – FD High Variance (€m)**
Group 1 - Priority Projects	2,946.2	2,012.5	2,946.2	-930.0	+3.7
Group 2 – Remaining Category 1 projects	428.1	152.5	428.1	-275.7	-
Group 3 – Category 2, 4 and Category 5 Projects	1,571.0	657.5	1,571.0	264.7	-
Group 4 – Remaining Category 3 projects	133.5	66.9	133.5	-66.6	-
Group 5 – Category 6, 7 and 8 projects	576.4	120.1	576.4	-	-23.8
Network Capex Total	**5,655.2**	**3,009.5**	**5,655.2**	**-1,007.5**	**-20.1**
Distribution Asset Management	15.5	0.0	15.5	-	+15.5
Enterprise Applications	13.5	6.5	13.5	+6.5	+13.5
Non-Network Capex Total	**29.0**	**6.5**	**29.0**	**+6.5**	**+29.0**
Customer Contributions	-340.0	-140.0	-340.0	-	-142.0
Interest During Construction	-	-	-	-	-
TAO Total	**5,344.2**	**2,846.0**	**5,344.2**	**-1,001.0**	**+8.7**
Transmission Total	**6,197.2**	**3,562.9**	**6,200.3**	**-943.8**	**+27.2**

[31] See Section 3.1.2.1.1 – CRU's position in the FD is that no PR6 *ex-ante* allowance should be provided to the TSO under SONI License Condition 42.
[32] TAO network capex exclusive of TSO network capex invoiced to the TAO.

3.2. Forecast Operational Expenditure

This section provides the CRU's position on the TSO and TAO's forecast opex items over the PR6 period (2026-2030). Table 24 below compares the TSO and TAO's requests for controllable opex to its baseline and high case allowances and shows the difference in those allowances since Draft Determination. For opex, the forecast expenditure is assessed looking at the baseline, trends, steps and outputs.

Table 24: Summary of Forecast Controllable Opex (2026 - 2030) Review

€m	Request	FD Baseline	FD High	Baseline DD v FD	High DD v FD
TSO Opex[33]	950.3	837.4	920.5	**+93.1**	**+96.2**
TAO Opex[34]	211.6	203.2	203.2	**+10.4**	**+10.4**

A more detailed assessment and breakdown of each network company's allowance is set out in the PR5 and PR6 TSO Opex Cost Assessment (CRU2025203) and PR5 and PR6 TAO Opex Cost Assessment (CRU2025204). The annual breakdown on allowances is also set out in Appendix 2. Please note that all costs set out in the review of forecast opex are in 2024 prices.

3.2.1. Review of TSO Forecast Operational Expenditure

The TSO has requested a total of €950.3m in controllable opex (excluding real price effects (RPEs) and ongoing productivity) for PR6, €1,934.5m in non-controllable opex and €745.4m in exceptional items. Table 25 below presents the overview of the PR5 outturn, the TSO's request, the CRU's Final Determination for PR6 and the variance since Draft Determination.

[33] Excluding Frontier Shift Request.
[34] Excluding Frontier Shift Request.

Table 25: TSO PR5 Outturn, PR6 Request and Draft Determination

TSO Opex (€m 2024 prices)	PR6 FD Request	FD Baseline Allowance (€m)	FD High Allowance (€m)	DD – FD Baseline Variance (€m)	DD – FD High Variance (€m)
Staff costs	430.6	382.3	415.9	+51.7	+8.1
Staff related costs	22.0	21.2	21.5	+2.6	+0.1
Contractors	120.7	96.6	120.6	+13.0	+37.0
Telecommunications	39.9	39.4	39.4	+0.5	+0.5
Premises	46.0	41.9	41.9	+3.0	+3.0
IT Costs	138.0	134.8	134.8	+17.1	+17.1
Insurance	4.8	4.5	4.5	-	-
Public Engagement	11.3	11.5	11.5	+0.2	+0.2
Professional Services	130.5	105.2	130.4	+4.9	+30.1
Grid Maintenance & Client Engineering	6.7	5.5	5.5	-	-
Rates	3.0	3.0	3.0	-	-
Promotion of Research	12.6	7.3	7.3	-	-
Intercompany Recharges	-15.9	-15.9	-15.9	-	-
Total Controllable Opex	**950.3**	**837.4**	**920.5**	**+93.1**	**+96.2**
Non-controllable Costs					
Inter TSO Compensation	18.5	18.5	18.5	-	-
CORESO subscription	6.5	6.5	6.5	-	-
Interconnector services	5.0	5.0	5.0	-	-
CRU Levy	15.0	15.0	15.0	-	-
DUoS costs	34.5	34.5	34.5	-	-
Ancillary Services	286.7	286.7	286.7	-	-
Future Arrangements for System Services	1,568.3	1,568.3	1,568.3	-	-
Total Non-Controllable Opex	**1,934.5**	**1,934.5**	**1,934.5**	-	-
Exceptional Items					
Security of Supply	600.1	600.1	600.1	-	-
Celtic Debt Service Costs	29.7	29.7	29.7	-	-
FASS funding costs	5.6	5.6	5.6	-	-
Clean Energy Package	110.0	110.0	110.0	-	-
Total Exceptional Items	**745.4**	**745.4**	**745.4**	-	-
PR6 (Excl. Frontier Shift)	**3,630.2**	**3,517.3**	**3,600.4**	**+93.1**	**+96.2**
PR6 (Incl. Frontier Shift)	**-**	**3,546.8**	**3,629.9**	**+95.5**	**+98.6**

3.2.1.1. TSO Opex

The following summarises some of the key points related to the assessment and recommendations on the TSO's PR6 base, trend and step controllable opex costs:

3.2.1.1.1. Staff and Staff Related Costs

This cost category includes base salary, pension, performance related pay and PRSI. The TSO requested a total of €452.6m for Staff and Staff Related Costs for PR6.

Draft Determination

A base of €253m was requested under this category. The TSO assumed a baseline FTE figure of 408 for 2024, 447 for 2025 and 524 for 2026. The TSO also clarified that in January 2025, they hired an additional 30 FTEs. Taking into account the FTE estimate for 2024 and the additional recruitment, the 2025 FTE figure of 447 was chosen as the baseline value for Draft Determination.

The 2025 FTE value of €98,236 which takes into account a newly negotiated pay deal was used. No trend was identified for these cost categories as FTE growth is linked to structural changes or specific programmes. The TSO also requested a step of €220.7m under this cost category.

The TSO requested a total of 872 FTEs by 2030, which represents a 95% increase from the baseline of 447 FTEs for 2025. In the TSO's view, this significant step change in FTEs is required to grow its organisational capacity sufficiently to close the perceived capacity and capability gap which emerged in PR5 and to build out capacity and capability to meet emerging and future obligations.

The final FTE numbers were obtained by building a bottom-up assessment of FTEs allocated per programme. The TSO's request proposed a baseline of 524 FTEs, while the projected figure for 2025 was 447 FTEs, a difference of 77 FTEs was attributed to vacancies. However, since the forecasted 447 FTEs was already used as the baseline, these additional 77 FTEs were interpreted as a step-change.

The TSO requested a total of 105 FTEs under seven of its non-network capex programmes (Digital Transformation, Technology Resilience and Modernisation, Cyber Security, Power System Capability Enhancement, TSO/DSO Coordination, Celtic Operational Readiness Programme and Control Centre Infrastructure). This is detailed in Section 3.1.2.1.

The TSO requested a total of 155 FTEs under its TSO Transformation and Capability Catchup programmes. The TSO clearly demonstrated the need for these programmes, which are necessary both in order to comply with local and EU decarbonisation policies, and to tackle a

recruitment and retention challenge necessary to deliver said goals. No alternatives for expenditure were explained, and no metrics were used to show that the costs incurred are reasonable. This resulted in an additional decrease in requested allowance.

To avoid limiting the TSO's ability to achieve key objectives, the CRU proposed putting in place a framework to allow access to additional allowances for extra FTEs if certain conditions are met. Firstly, the TSO must demonstrate that they have hired at least 60% of the allowed FTEs. For example, if at the beginning of PR6 10 additional FTEs are allowed for 2027, the TSO must have recruited at least 6 FTEs (60% of 10) before requesting additional allowances for labour. Secondly, the TSO must provide a clear link between the requested FTEs and specific programmes and outputs.

This resulted in a step adjustment of €117.5m.

Summary of Response

In the Draft Determination, the CRU set a base of 447 FTEs. This assumed that 77 additional FTEs, which the TSO was requesting as "current vacancies", would not be included in that base. If they had been included, the total would have been 524 FTEs. This exclusion was because those 77 FTEs were presented as vacancies rather than as current employees. In its response, the TSO has clarified that its current FTE level is 532, which is 85 more than the previously assumed base of 447.

On incremental FTEs within the TSO Transformation and Capability Catch-up non-network capex programmes, the TSO states that it provided granular detail on the substance, drivers and rationale for the requested FTE requirements. This was duly reviewed as part of the Draft Determination process. However, the TSO also states that it is prepared to accept reduced baseline allowances for these programmes, given that there are reopener mechanisms that will allow for an increase later in PR6, when the network company is closer to the point of need.

On incremental FTEs for the Delivery Roadmap programmes, the TSO has provided further detail on the activities that each FTE within each subprogramme will carry out.

Lastly, the TSO has pointed out that the FTE unit cost used at Draft Determination (€98,236) did not include the 2% negotiated pay agreement for 2026. Applying this 2% increase gives an FTE unit cost of €100,200.

Final Determination

Given the additional information provided on the current number of FTEs employed on opex activities by the TSO, these are now included within our base of 532 FTEs. This represents an increase of 85 FTEs relative to those used for the base at Draft Determination.

For the TSO Transformation and Capability Catch up non-network capex programmes, the TSO has directed the CRU to a previously submitted and reviewed supplementary question response and has accepted a lower baseline in light of the reopener mechanism. Therefore, no changes have been made to the projected number of FTEs.

For the Delivery Roadmap programmes, additional information on the activities to be carried out by each FTE has been provided. However, at Draft Determination, FTEs associated with Delivery Roadmap programmes were modelled with the adjustments imposed on non-network capex, given that the underlying assumption is that those programmes are driven by capex activities. In light of further information provided on capex, the downward adjustment has been reduced across all six subprogrammes.[35] This reduction in adjustments implies an increase in FTEs associated with these programmes, from 89 by 2030 at Draft Determination to 95 by 2030 in the Final Determination estimate.

Lastly, the FTE unit cost has been updated to reflect the negotiated pay agreement for 2026. This means that the unit cost has increased by 2% from €98,236 to €100,200.

Overall, these adjustments imply a total allowance of €382.4m for Staff Costs, up €51.8m or 15.6% from €330.6m at Draft Determination, and a total of €21.2m for Staff Related Costs, up €2.7m or 14.6% from €18.5m at Draft Determination.

3.2.1.1.2. Contractors

Contractors are typically used to either support existing staff in their operations or to assist in resourcing challenges.

[35] The six Delivery Roadmap programmes refer to Cyber Security, Digital Transformation, Technology Resilience and Modernisation, TSO/DSO Coordination, Power System Capability Enhancement, Control Centre Infrastructure.

Draft Determination

The TSO requested €120.7m under this cost category for PR6 with a base of €76m.

Contractor costs increased significantly between the PR5 allowance and outturn, which was driven by unforeseen events such as the Security of Supply Programme, the need to deliver a higher number of outputs and recruitment/retention challenges. Therefore, the outturn average from 2023 and 2024 of €9.2m was deemed an inappropriate baseline as we do not account for unforeseen events in PR6 and internal FTEs are expected to grow significantly.

To calculate the baseline, we estimated the average annual difference between PR5 allowance and outturn of €6.1m. We then subtracted this from the outturn average from 2023 and 2024 of €9.2m which leads to an adjusted annual baseline of €3.0m and a total PR6 baseline of €15.2m. This represented a €60.8m difference from the TSO request, which was treated as a requested step as the baseline should only reflect business-as-usual (BAU) activities.

Additionally, the TSO submitted a trend cost for this category which was treated as a step as there are no cost drivers.

The TSO requested a step of €60.8m for PR6. As noted above, activities identified as non-BAU and the requested trend were treated as a step, resulting in a total step request of €105.9m.

While the need was clearly demonstrated, the proposed additional quantities were not clearly linked to the BPQ submission, suggesting an incomplete understanding of additionality. Regarding cost efficiency, no benchmarking exercise was conducted, there was no clear explanation of how these additional expenses deliver value to consumers and there is no clarity on how these costs were estimated. A step adjustment of €23.8m was proposed.

Summary of Responses

The TSO states that the requested contractor baseline figure reflects 2025 actual cost lines, which the company expects to continue seeing throughout PR6. The TSO states that, while this represents a step change relative to PR5, this is a reflection of overall baseline activity growth. The suggested necessary base, derived from 2025 costs, is €15m per year. The TSO has clarified that the increase in Contractors has not been driven by exceptional events that are not to be expected in PR6, but rather by a ramp-up in BAU activities.[36]

[36] This rationale also applied for Professional Services.

Additionally, the TSO welcomes the reopener mechanism and is willing to accept a reduced contractor provision within the baseline.

Final Determination

First, given that the TSO has clarified that the increased expenditure in PR5 was driven by a general ramp-up in BAU operations, and not by one-off, exceptional events, the downwards adjustment to the base that was being applied at Draft Determination has been removed. This downwards adjustment was reducing the PR5 outturn to PR5 allowances levels. The removal should yield base values more similar to the PR5 outturn.

Furthermore, and also relative to the base, the method to estimate the base has been modified from using the outturn average of 2023 and 2024 to the average of 2024 and 2025. This is a reflection of the CRU and our advisors' recognition that an emphasis on later years better reflects the ramp-up stage within this cost category.

There have been no responses related to the trend nor step of this category, which implies that all the change in this category stems from a base change. The allowance for Contractors for PR6 is €96.6m, up €13.0m or 15.6% from €83.6m at Draft Determination.

3.2.1.1.3. Professional Services

Similarly to Contractors, Professional Services are typically used to either support existing staff in their operations or to assist in resourcing challenges.

Draft Determination

The TSO requested €130.5m under this cost category, with a base of €40.0m.

This cost category grew by €17.1m from PR5 allowance to outturn for the same reasons outlined in relation to the Contractors cost category. Therefore, using the same rationale in setting an appropriate baseline, a baseline of €5.2m was provided. This represents a €13.9m difference from the TSO request, which similarly to the Contractor cost category was treated as a requested step.

Additionally, the TSO submitted a trend cost for this category which was treated as a step as there are no cost drivers. Activities identified as non-BAU and the requested trend are treated as a step, which resulted in a total step request of €106.4m.

Like the Contractors request, while the need was clearly demonstrated, the proposed additional quantities were not clearly linked to the BPQ submission. Regarding cost efficiency, no benchmarking exercise was conducted, there was no clear explanation of how these additional

expenses deliver value to consumers and there was no clarity on how these costs were estimated. A step adjustment of €74.1m was proposed.

Summary of Responses

The TSO's response on Professional Services refers to the Contractors response. In other words, the same arguments for Contractors apply for Professional Services. See Section 3.2.1.1.2 above for further information.

Final Determination

Similarly to Contractors, two adjustments have been made for the Final Determination. First, the downwards adjustment that was applied to the base has been removed, which was producing a base based on the PR5 allowance rather than on the outturn. This is because the clarification provided by the TSO highlights that costs for Professional Services increased during PR5 as part of a consistent ramp-up in costs, and that this increase was not driven by one-off, exceptional events. Consequently, we would expect to see these levels of expenditure as recurring throughout PR6.

Second, we move from using the average of outturn years 2023 and 2024 to using 2024 and 2025. This is to better capture the ramp-up state of this cost category.

There have been no responses related to the trend nor step of this category, which implies that all the change in this category stems from a base change. The allowance for Professional Services for PR6 is €105.2m, up €4.9m or 4.9% from €100.3m at Draft Determination.

3.2.1.1.4. Premises

This cost category includes the rent that the TSO pays for use of its premises.

Draft Determination

The TSO requested a total of €46m under this cost category and a base of €40.5m. The 2023 and 2024 outturn was not deemed an effective baseline as it includes an underspend driven by factors that are not anticipated in PR6. This resulted in an adjusted proposed base of €35.1m.

Premises costs are related to non-network capex activities the TSO has proposed in its business plan submission; therefore, we considered the request for these costs, which typically fall under the programmes the TSO proposes to put in place during PR6, alongside non-network capex.

The TSO requested a step of €3.9m under this cost category. The Physical Control Centres non-network capex programme served as justification for the requested step increase. A step adjustment of €3.7m was allowed. During the CRU's quality assurance process prior to

publication of Draft Determination, it was identified that the proposed step for Premises of €3.7m was included in error. The TSO's request was subsequently proposed to be allowed in full.

Summary of Responses

The TSO stated in its response that the CRU used the 2023 and 2024 outturn to estimate the base for this cost category. Given that during PR5 there was an underspend due to a rent-free period at the Oval, this would result in a lower allowance for this category than is needed to maintain BAU operations.

Final Determination

The base analysis used at Draft Determination did not use solely the PR5 outturn as a determining factor. The PR5 outturn was uplifted by the difference between the allowances and the outturn, which was €2.2m (i.e., a €0.44m uplift per year).

However, even after this adjustment, the base value remains below the actual and forecast expenditure levels for 2024 and 2025. To remain consistent with the principle that the base for Premises costs should cover the existing rent, this adjustment is removed and instead the base has been set to equal to the average expenditure over 2024 and 2025.

On the step, while the TSO has not addressed this point in their response, we have applied an uplift driven by a reduction in non-network capex adjustments related to Delivery Roadmap programmes. This reduction in the adjustment increases the step for Premises.

Overall, the allowance for Premises at Final Determination is €41.9m, up €3.1m or 8.0% from €38.8m at Draft Determination.

3.2.1.1.5. IT Costs

This category includes, but is not limited to, software costs, costs for increasing cyber security resilience and cloud-based data storage.

Draft Determination

The TSO requested a total of €138m under this cost category.

IT costs are related to non-network capex activities the TSO has proposed in its business plan submission; therefore, the CRU considered the request for these costs, which typically fall under the programmes the TSO proposes to put in place during PR6, alongside non-network capex. The need for the IT costs trend was not justified as no cost driver was identified. It was therefore reinterpreted as a step.

The TSO requested a step of €73.5m under this cost category. The Cyber Security, Digital Transformation, Technology Resilience and Modernisation, TSO/DSO Coordination, Power System Capability Enhancement and Physical Control Centres non-network capex programmes served as justification for the requested step increase. A step adjustment of €67.7m was proposed.

During the CRU's quality assurance process prior to publication of Draft Determination, it was identified that the proposed step for IT costs of €67.7m was included in error. This amount was to be adjusted upwards for costs related to the Physical Control Centres non-network capex programme.

Summary of Responses

The TSO highlighted in their response that the trend for IT costs is driven by an increase in workforce. This growth in workforce is required to cover more laptops, servers and cloud assets. Moreover, further details were provided on how the cost category was built up and what licenses are included in the proposed costs.

Final Determination

The only adjustment for IT costs lies within the trend given the increase in FTEs, which will require additional laptops, servers and cloud assets.

A two-step process was followed to estimate the trend. First, using a unit cost based on the 2025 FTEs and, to be consistent with said value, using the 2025 forecast outturn. This yields a base unit cost of €18,800 per FTE.

Second, we use this unit cost to project the trend growth in IT costs. In doing so, we do not directly apply the modelled FTE growth used for the Staff and Staff related costs category. Because we are already including a step increase in IT Costs from the Delivery Roadmap programmes, we exclude the FTEs associated with those programmes from this projection.

The inclusion of this trend yields a total estimate for Final Determination of €135.0m, up €17.3m or 14.7% from €117.7m at Draft Determination.

3.2.1.1.6. Insurance

Insurance costs have increased throughout PR5 driven by a general increase in insurance costs and tightening of the market post-COVID, and there is no evidence to suggest that decreases are expected. The TSO requested a total of €4.8m under this cost category.

Draft Determination

The TSO requested a base of €4.8m under this cost category. Taking the outturn average from 2023 and 2024 the CRU's proposed base was set at €4.6m.

Summary of Responses

The TSO has said that, while it will try to secure the best market rates, it has limited ability to influence costs. For this reason, the TSO claims that this cost should be allowed in full.

Final Determination

Given that no additional information has been provided to explain why the TSO's proposed increase takes the value that it has, and that the TSO states it has limited influence over these costs and will seek to secure the best available market rates, the CRU and our advisors have limited confidence that costs will necessarily evolve in line with the TSO's proposal. Therefore, no adjustments have been made to the Draft Determination proposal of €4.6m.

3.2.2. Review of TAO Forecast Operational Expenditure

The TAO requested a total of €211.6m in controllable opex and €215m in non-controllable opex for PR6. The total TAO opex of €409.8m is €16.8m (3.9%) below the TAO's requested allowance of €426.6m.

Table 26 below presents the overview of the PR5 outturn, the TAO's request and the CRU's Draft Determination.

Table 26: PR6 Request, Final Determination and DD – FD Variance

TAO Opex (€m 2024 prices)	PR6 Request (€m)	Final Determination (€m)	DD – FD Variance (€m)
Transmission Operations	21.8	20.9	+7.9
Planned Maintenance	115.4	115.4	+2.8
Fault Maintenance	12.7	11.9	-
Transmission Retirements	-	-	-
Asset Management[37]	5.8	4.8	-
Company Wide Costs	2.1	2.1	-
Corporate Charges	20.6	17.9	-
Insurance	1.5	1.5	-
Legal	0.8	-	-
Pension	0.9	1.0	+0.2
IT Opex	3.3	2.5	-0.8[38]
Miscellaneous	-	-	-
Professional Fees	15.0	14.3	+0.5
Telecom Fees	11.7	11.0	+0.0
Total Controllable Opex	**211.6**	**203.2**	**+10.4**
Network Rates	198.3	198.3	-
CRU Levy	16.7	16.7	-
Total Non-controllable	**215.0**	**215.0**	**-**
Total (Excl. Frontier Shift)	**426.6**	**418.2**	**+10.4**
Total (Incl. Frontier Shift)	**426.6**	**419.5**	**+11.2**

3.2.2.1. TAO Opex[39]

This section summarises some of the key points related to the assessment and recommendations on the TAO's PR6 base, trend and step controllable opex costs. Please note,

[37] This cost category was referred to as 'Wayleaves' during PR5.
[38] The reduction on IT Opex is because, at Draft Determination, we included in the total a €3.3m allowance for IT Opex, when our estimate was €2.5m.
[39] In this section, we will cover only those cost categories where we have made the largest adjustments relative to Draft Determination.

the following points only focus on a selection of cost categories, further analysis is presented in the PR5 and PR6 TAO Opex Cost Assessment (CRU2025204).

Based on the evidence submitted, the CRU has used 2023 and 2024 figures to set the baseline. The basis for selecting these years is the same as the TSO and is set out in Section 0, with the caveat that the baseline may be adjusted where there is evidence to suggest that this approach could represent an inappropriate baseline. The following summarises the key points related to the assessment on the TAO's PR6 baseline costs:

3.2.2.1.1. Transmission Operations

The TAO requested a total of €21.8m under this cost category.

Draft Determination

The TAO requested a base of €18.4m under this cost category. The average of 2023 and 2024 was €3.6m, slightly below the TAO submission of €3.7m per year. The baseline was adjusted downward by €5.6m or €1.1m per year which reflected that levels of outturn at the time, which while justified for PR5 due to external unforeseen events, did not reflect a BAU cost of the activity. This resulted in a base of €12.5m.

Using the length of the network, a trend of €0.4m was estimated over PR6, €3.0m lower than the TAO's request of €3.4m.

Summary of Responses

For the base, the TAO stated that the CRU's initial assumption at Draft Determination that the outturn being significantly higher than the allowance was due to extraordinary events and not to be expected during PR6 was incorrect. The TAO stated that the higher outturn the CRU observed at PR5 is a reflection of a new operational baseline rather than an anomaly. This is the consequence of an increasing complexity of operations as Ireland moves towards decarbonisation.

The TAO also stated that as Ireland's transmission network evolves to meet the demands of decarbonisation, the operational landscape becomes more complex. In other words, the delivery of Ireland's CAP introduces a complexity factor to the trend modelled by the TAO. This complexity factor acts as a multiplier of the trend.

Final Determination

First, on the base, the downward adjustment applied at Draft Determination has been removed. This adjustment was in place due to the CRU and our advisors' understanding that the excess

expenditure during PR5 was due to exceptional events, and that those would not be an accurate reflection of recurring, BAU costs looking into PR6.

Second, the CRU recognises that a complexity factor may increase costs. However, the CRU do not think this is quantifiable through the trend. Therefore, the 'complexity factor' request is reinterpreted as a step rather than as part of the trend. The CRU consider the need and additionality of this step to be completely justified. A 20% downward adjustment is applied to this additional step to signal a lower degree of confidence on how the value was estimated, and whether it will evolve as requested throughout PR6.

Overall, these adjustments increase the allowance for Transmission Operations at Final Determination to €20.9m, up €7.9m or 62% from €12.9m at Draft Determination.

3.2.2.1.2. Planned Maintenance

This cost category consists of ongoing costs required to maintain and ensure the reliability of transmission infrastructure.

Draft Determination

The TAO requested a total of €115.4m under this cost category.

The TAO requested a base of €120.8m under this category. The average of 2023 and 2024 was €23.6m. This resulted in a baseline allowance of €117.9m for PR6.

Summary of Responses

The TAO has provided benchmarking information of its maintenance performance through participation in ITOMS (International Transmission Operations and Maintenance Study), which supports the TAO's proposals on substation costs and overhead line costs.

Furthermore, the TAO has requested an adjustment to the base modelled by the CRU at Draft Determination, arguing that it should have been based on the 2024 outturn. Although 2024 is the year cited, we understand this to be a typo, as the TAO has modelled its request on the 2023 outturn values.

Final Determination

In the Draft Determination, the CRU fully accepted the negative trend requested by the TAO. However, applying this negative trend to a different base year than the one used in the TAO's modelling could result in a double reduction in allowances.

To address this, for the Final Determination the CRU has decided use 2023 as the base year. This change increases the Final Determination allowance for Planned Maintenance to €115.4 million, in line with the TAO's request.

3.2.2.1.3. Professional Fees

Draft Determination

The TAO requested a step of €3.4m under this cost category. Regarding additionality, although it is reasonable to expect that increased operations and new initiatives would lead to higher costs relative to the baseline, it was unclear why the requested value was chosen. Regarding cost efficiency, the TAO did not demonstrate whether the proposed costs were benchmarked, whether they deliver clear value to the Irish consumer or whether the approach reflects reasonable use of resources. This resulted in a step of €2.3m.

Summary of Responses

The TAO addressed the additionality and cost efficiency question, which was an adjustment raised at Draft Determination.

The TAO clarified that there was a need for an increase, which is explained by membership of ITOMS, other international benchmarking associations and expertise being sought through the Joint Outage Transformation Programme. This is also meant to address increasing levels of stakeholder engagement and conferences with professional facilitations.

Furthermore, the TAO explained that efficiencies are meant to be achieved through competitive procurement, framework contracts, internalising work, and project planning.

Final Determination

Given the additional information provided, for the Final Determination a downward adjustment is applied to the additionality and efficiency reductions. As a result, the allowance for Professional Fees in the Final Determination is €14.3m, €0.4m or 2.9% higher than the €13.9m allowance at Draft Determination.

3.2.3. Frontier Shift

The CRU has decided to apply an *ex-ante* adjustment to allowances to account for ongoing efficiency and RPEs in PR6, collectively referred to as 'Frontier Shift'.

The CRU aims to ensure that customers only pay for the efficient costs of developing, maintaining and operating the electricity transmission and distribution systems. This is done by setting the network companies challenging but realistic and achievable targets and incentives.

The CRU applies a Frontier Shift allowance which includes an ongoing efficiency / productivity challenge which is to encourage network companies, to implement new technologies and management practices, replicating the forces of competition to drive out cost efficiencies. This allowance also accounts for RPEs, which are adjustments that reflect changes in the price of inputs net of HICP inflation adjustments that are already applied under the regulatory framework.

More detail can be found in the Price Review Six Inflation Trends and Ongoing Efficiency Information Paper (CRU202593).

Draft Determination

Overall, the CRU proposed to apply the Frontier Shift adjustments to allowed opex, summarised in Table 27 below.

Table 27: Frontier Shift Draft Determination

Network Company	PR6 Factor
EirGrid (TSO) Frontier Shift (per annum)	0.9%
ESB Networks (TAO) Frontier Shift (per annum)	0.1%

The CRU concluded that this proposal reflected:

- An ongoing efficiency challenge which was stretching but achievable, supported by CEPA's analysis, satisfying one of the key PR6 objectives to increase efficiency and protect customers; and
- A reasonable *ex-ante* provision for RPEs, which will enable EirGrid to manage the risk of input costs increasing (noting that the *ex-post* assessment process will be retained and used to review whether EirGrid efficiently managed input price pressures within the revenue control period).

As the proposed overall Frontier Shift adjustment was positive (i.e. an increase in allowed opex), this implied that RPEs in opex were expected to be greater than the scope for the DSO to achieve productivity improvements during PR6.

Summary of Responses

Both EirGrid and ESB Networks stated that macroeconomic trends in the Irish economy and the degree of dynamic change taking place within the electricity sector during PR6 limit the scope for achieving ongoing efficiencies. EirGrid asked that the implied ongoing efficiency challenge of

0.5% assumed at Draft Determination be reviewed stating that the application of the proposed Frontier Shift would create delivery challenges.

ESB Networks, through its consultants Frontier Economics, presented alternative analysis indicating greater scope for RPEs in PR6, combined with less scope for ongoing efficiency, and asked for the frontier shift adjustment at Final Determination to reflect this.

Final Determination

The CRU had applied a net Frontier Shift adjustment of *circa* 0.9% and *circa* 0.2%, for the TSO and TAO, respectively. The allowance adjustment has reduced slightly for the TSO (slightly to a second decimal place) and increased for the TAO since Draft Determination based on updated information in HICP and the various indices used to estimate labour, materials, business services, IT and telecoms RPEs.

The CRU remain of the view that there is scope for ongoing productivity improvements on opex in PR6, while also recognising the value in providing *ex-ante* allowance for RPEs given the considerable scale of investment and the risk of substantial cost forecast changes due to input cost volatility and supply chain constraints in PR6. This net Frontier Shift adjustment will also provide reasonable *ex-ante* provision for RPEs, which will enable the TSO and TAO to manage the risk of input costs increasing. Noting that in line with recent price reviews, the *ex-post* assessment process will be retained and used to review whether network companies efficiently managed input price pressures within the period.

The TSO and TAO is expected to manage within its overall opex allowance during the price control period prior to the *ex-post* review.

In line with the approach proposed at Draft Determination, the CRU is not applying an *ex-ante* Frontier Shift adjustment for capex, given the challenges in identifying appropriate indices in which to base the *ex-ante* allowance.

Table 28: Frontier Shift Final Determination

Network Company	PR6 Factor
EirGrid (TSO) Frontier Shift (per annum)	0.9%
ESB Networks (TAO) Frontier Shift (per annum)	0.2%

3.3. Conclusions

The CRU has decided to allow the TSO and TAO access to €716.9m and €3,016.0m (excluding customer contributions) of baseline capex. These allowances are to cover the capex for the 2026 to 2030 period.

The CRU is allowing of €3,517.3m and €418.2m for opex for the TSO and TAO, respectively, excluding Frontier Shift. These values are inclusive of non-controllable elements. We note that the CRU has only evaluated controllable opex and treats the non-controllable costs in this paper as passthrough.

The CRU has also decided to ringfence a proportion of the TSO and TAO's allowances for use in uncertainty mechanisms, DOs, volume drivers and re-openers.

Table 29 summarises PR6 forecast capital and opex for the TSO and TAO. The CRU has allowed a total of €11.1bn (including customer contributions and Frontier Shift) that the TSO and TAO can request through the AIMF which will help release more funds to manage uncertainties.

Table 29: Summary of PR6 Capital and Operational Expenditure for the TSO and TAO

Categories	PR6 Request (€m)	PR6 FD Baseline (€m)	PR6 FD High (€m)	DD – FD Baseline Variance (€m	DD – FD High Variance (€m)
TSO Opex (excl. Frontier Shift)	3,630.2	3,517.3	3,600.4	+93.1	+96.2
TSO Opex (incl. Frontier Shift)	-	3,546.8	3,629.9	+95.5	+98.6
TAO Opex (excl. Frontier Shift)	426.6	418.2	418.2	+10.3	+10.3
TAO Opex (incl. Frontier Shift)	-	419.5	419.5	+11.2	+11.2
TSO Capex	877.1	716.9	856.1	+57.2	+18.5
TAO Capex	4,289.9	3,016.0	6,540.3	-1,001.0	+8.7
Customer Contributions	-140.0	-140.0	-340.0	+0.0	-142.0
Total (excl. Frontier Shift)	**9,083.8**	**7,528.4**	**11,075.0**	**-840.4**	**-8.3**
Total (incl. Frontier Shift)	**-**	**7,559.2**	**11,105.8**	**-837.1**	**-5.0**

4. The Regulated Asset Base

This section sets out the details related to the TSO's and TAO's Regulated Asset Base (RAB) for the PR6 period. Specifically, this section provides information on:

- the type of assets within the TSO's and TAO's RAB;
- the methodology used to value the assets within the RAB;
- the length of asset lives applied to the assets within the RAB;
- the depreciation methodology applied to the RAB;
- the regulatory practice when an asset is physically replaced prior to being fully depreciated; and
- the regulatory treatment of (1) additions to the RAB and (2) claw back of revenue earned on assets that were not put in place.

4.1. Introduction

The revenue that is recovered from the TUoS customer during each review period can be divided into three separate categories:

1. Revenue to recover the TSO's and TAO's opex costs during the period;
2. A return on capital invested in the TSO's and TAO's assets; and
3. Revenue to cover depreciation on the TSO's and TAO's assets.

The RAB plays a key role in the determination of the amount of depreciation that the TSO and TAO receive (item 3 above) and is the base to which the rate-of-return is applied when determining the return on capital for the TSO and TAO (item 2 above). This section provides information on a number of interrelated issues that determine the TSO and TAO RAB, respectively, including:

- The value and composition of the TSO and TAO's RAB;
- The asset lives applied to the assets within the TSO and TAO's RAB; and
- The depreciation methodology applied to the TSO and TAO's RAB; and

- The regulatory treatment of (1) earlier than anticipated asset replacements, (2) additions to the RAB and (3) the clawback of revenue earned on assets that were not put in place (i.e. the PR4 capex underspends).

4.2. Value and Composition

The approach to valuing the assets within the RAB is also an important decision within the price review process.

The CRU will continue its current approach for valuation of the RAB through the next price review period. This decision is based on providing regulatory certainty and maintaining regulatory precedent regarding the valuation of the RAB. This was the established practice during the last four price review periods.

This approach allows the CRU to focus on reviewing other aspects of the TSO's and TAO's performance to ensure that the electricity networks are operated and developed in a cost effective and efficient manner. For further details on this approach and other approaches please see Appendix 3.

Table 30 and

Table 31 below set out the CRU's forecast of the RAB for PR6 for the TSO and TAO, respectively.

Table 30: TSO RAB 2026 - 2030[40]

2024 €m	2026	2027	2028	2029	2030
OAV	160.83	243.62	299.95	307.99	262.32
Capex	134.75	130.74	101.55	56.33	46.13
Depreciation	-51.96	-74.40	-93.52	-102.00	-96.90
CAV	243.62	299.95	307.99	262.32	211.55

[40] Based on a baseline capex spend. Should the TSO spend reach the full "base & AIMF" capex spend, the closing PR6 is higher at €257.1m. The detailed RAB profile can be found in the TSO PR6 FD Revenue model.

Table 31: TAO RAB 2026 - 2030[41]

2024 €bn	2026	2027	2028	2029	2030
OAV	3.71	3.94	4.36	4.86	5.44
Capex	0.36	0.56	0.65	0.75	0.81
Depreciation	-0.12	-0.13	-0.14	-0.16	-0.18
Secondary Asset Adjustment (PR5)	-0.01	-0.01	-0.01	-0.01	-0.01
CAV	3.94	4.36	4.86	5.44	6.06

Please refer to the CRU's revenue models published alongside this Final Determination for detailed composition of the TSO's and TAO's RABs.

4.3. Asset Lives Applied to the RAB

The assets lives applied to assets within the RAB feed through into the level of depreciation that the TSO and TAO receives on those assets within each control period (or year).

Draft Determination

For PR6, the CRU proposed to continue using the assets lives as determined in PR5, a breakdown of which is provided in Appendix 3.

Prior to the CRU's Draft Determination, and as part of its PR6 business plan submission, ESB Networks requested a reduction on the asset lives for network assets in PR6, and provided supporting information, commissioned by its consultants WSP.[42]

WSP's report described the methodology it used to estimate new asset lifetimes primarily for distribution assets, but also with reference to transmission assets. The estimations were based on the change in asset profile data between PR5 and PR6 for each installation year, which in turn was used to determine the volume of assets removed and the average age of assets when

[41] Based on a baseline capex spend. Should the TAO spend reach the full "base & AIMF" capex spend, the closing PR6 is higher at €8.4bn. The detailed RAB profile can be found in the TAO PR6 FD Revenue model.
[42] WSP's technical report was provided to the CRU as part of the DSO's business plan submission (full version received in early May 2025).

removed from service. This data was summarised to determine the retirement age which was compared against the rated technical life of the asset. WSP's assessment concluded that "*In general, the calculated average asset age at retirement for each asset category tends to be lower than the rated technical lifetime, which supports a reduction in the economic life*."

The CRU noted concerns with the proposal submitted by ESB Networks on asset lives, including that the WSP report focused primarily on 'retirement age' as opposed to 'asset life', and that the primary examples given were for replacement due to overloading of 110 kV and 38 kV transformers and changes in engineering standards for pole mounted transformers.

While it is recognised that some assets may need to be retired ahead of their asset lifetime due to reasons other than non-load related intervention, the CRU did not consider it appropriate to adjust the asset life for these instances. Instead, the asset lifetime estimations should be based on the technical performance of an entire asset group, informed by data related to non-load related replacements.

It is anticipated that over the course of PR6 and PR7 a large volume of load related interventions will be required. Adjusting the asset life in accordance with the methodology outlined in the WSP's report would result in a significant decrease in asset lifetime. However, the new assets installed as part of the load related interventions would be expected to have an asset life in line with industry standards and not a shortened lifetime, skewed because of load related inventions previously made. In addition, changes in engineering standards should not result in programmes to retrospectively replace existing assets. Instead, asset replacements should be driven either by load related or non-related reasons as opposed to changes to engineering standards to increase capacity of assets.

Any future change to the asset life would need to be based on substantive evidence to demonstrate that particular asset groups were experiencing failures or accelerated deterioration, resulting in the need to reduce the asset lifetime.

Summary of Responses

Several responses were submitted on asset lives, and depreciation more broadly. This included feedback from Department of Enterprise, Tourism and Employment (DETE) with concerns over the "*criticality of controlling network development costs during PR6 and beyond 2030*", and that the "*CRU and [system operators] SOs must ensure that the [Final] PR6 Determination and proposed customer cost recovery is underpinned by an appropriate assessment of the true lifespan of new network assets, and associated depreciation rate in asset value and cost-recovery*".

DETE supported further review of this issue, encouraging the CRU and the network companies to determine whether it was more appropriate to recover the costs of some new network assets from final customers over a longer period of time.

The Economic and Social Research Institute (ESRI) also responded on this issue, reiterating the need for network charges to be cost reflective in order to guide good investment and consumption decisions. ESB Networks also responded on this issue, restating its proposal to shorten asset lives, while adding that adjustments to asset lives may be warranted to better align cash flows with investment delivery and enhancing credit metrics.

Final Determination

For PR6, the CRU will apply the asset lives as set out in Table 32 below.

Table 32: Asset Lives for PR6 - Transmission

Asset	PR6 (yrs.)
Network Assets	50
Telecoms	50
Office Equipment	10
SCADA Telecoms	15
Premises	23 or 50
IT	5
Customer Contributions	50
Secondary Assets	10
Enterprise Applications/Systems	5

The CRU remain of the view that the asset lives set out above remain appropriate for PR6 and that there is no strong technical basis for changing asset lives. There is broad consensus, supported by regulatory precedent, that traditional network assets have a technical life in line with the asset lives set by the CRU.

While ESB Networks, and its consultants WSP, have identified some specific manufacturer-related issues and operational conditions that may impact the technical lives for some asset classes, and particular legacy assets, our assessment finds that this should not be applied broadly, and does not serve as the basis for altering the CRU's asset lives for PR6.

Some specific issues identified in ESB Networks' submissions on asset lives for PR6, related to the early retirement / replacement of assets, based on the expansion and uprating of the transmission and distribution networks and the increasing role of secondary assets on both networks, have already been addressed by the CRU at PR5 and prior price reviews. Firstly, at

PR5 the CRU acknowledged that secondary assets have shorter asset lives compared to primary network asset lives, and decided to introduce a secondary assets category, and set the asset life at 10 years for the TAO and 10-15 years for the DSO. Secondly, over several price review cycles now, the CRU has stated that when an asset within the RAB is replaced before its value has been fully depreciated, the residual value of the asset should be fully removed by ESB Networks from its RAB.

In undertaking further review of this issue though since Draft Determination, the CRU has identified two issues in the way these previous decisions have been implemented. This includes the allocation of capex to the secondary assets asset category, for the purpose of depreciation, across both the TAO and the DSO, and the potential overlap with other asset life categories such as IT, telecoms, protection and control. This has now been remedied and captured in the updated revenue modelling. Please refer to the CRU's TSO and TAO revenue models (CRU2025209 and CRU2025210) published with this Final Determination for detailed breakdown of the allocation of capex to the secondary assets asset category.

The CRU's policy on replaced assets, and the issue identified through our review, is discussed further below.

4.4. Depreciation Methodology

Economic depreciation profiles allocate the original capital cost of a project over its useful life. There are a number of possible methods through which asset bases may be depreciated; common relevant examples are straight-line, sum-of-years-digits and declining balance depreciation.

When setting the first revenue control, covering the period 2001 to 2005, the CRU chose the straight-line method. The following benefits were noted.

- Due to the nature of the design life of network assets and the load profile of the use of network assets, the straight-line method was a reasonable representation of economic depreciation for network assets.

The straight-line approach to depreciation was then continued when setting the second, third and fourth Price Reviews.

For PR6, the CRU will continue applying the straight-line method of depreciation used during previous price review periods. Maintaining regulatory certainty by continuing this methodology was a key factor in this decision. However, regulatory certainty aside, the rationale that led to this approach being chosen in the first instance are still applicable for the forthcoming period.

4.5. Replaced Assets

When setting the price review covering the PR2 period from 2006 to 2010, the CRU noted that a significant amount of expenditure had taken place in the last decade on replacing assets. The concern was that this could lead to a situation where an asset and its subsequent replacement would both be included in the RAB at the same time, that is, the asset has been replaced before its value in the RAB has been fully depreciated. In the PR2 decision paper (affirmed in subsequent decisions) the CRU stated its view that assets included within the RAB that have been replaced should be removed from the RAB at the time of their replacement.

At Draft Determination, the CRU proposed that this policy should continue to be applied during the PR6 period where material values of assets are replaced before being fully depreciated, while recognising that use of an average asset life for a class of assets may extend a subset of assets beyond their planned depreciation life.

As noted above, following Draft Determination, the CRU has identified an issue with how the CRU's Replaced Assets policy is being implemented by ESBN. The CRU's review indicates that no specific replaced assets adjustment has been applied for network assets that have been replaced. Thus, a portion of both the DSO RAB continues to reflect assets that are no longer physically on the networks.

Significant engagement has been carried out between the CRU and ESBN on the issue, including in trying to understand the materiality of the portion of the RAB that no longer reflects assets physically connected to the network (the 'replaced assets).

It should be noted though that there are significant challenges in determining the appropriate adjustment to account for the replaced assets, given the complexity in identifying the value of assets physically on the networks, the residual value of these assets still on the RAB, and the residual value of any replaced assets still on the RAB.

Preliminary estimates from ESBN indicate a wide potential range for the value of replaced assets. As such, the CRU requires further detailed analysis to ensure that any revenue adjustment applied is robust and in the best interests of customers. Incorrect estimation carries significant risks; overestimating could result in excessive depreciation, while underestimating could lead to under-recovery of costs and a RAB that still includes assets already replaced, contrary to the CRU's depreciation policy.

ESBN has provided an indicative current cost accounting estimate for the residual value of replaced assets within the RAB. The range provided by ESBN included valuations of €394 million and €778 million (TAO and DSO). This range is preliminary and subject to detailed review.

The CRU reiterates its policy, that when an asset is physically removed from the network, the residual value of the asset still on the RAB should be depreciated. The CRU is committed to ensuring that this policy is correctly implemented during PR6, and that the issue identified during this review is corrected during PR6, and at future reviews if the issue persists or reoccurs. The CRU will continue to work with ESBN to determine the appropriate replaced asset adjustment value and to make a decision on the mechanism. The CRU anticipates making this adjustment from the tariff year 2027/28.

4.6. Capital Expenditure Approved but not Incurred

The CRU has decided that revenue collected by the TSO or TAO to cover return and depreciation on projects which were planned for the 2021 to 2025 period and subsequently not put in place will be netted off the revenue to be collected by the TSO and TAO during the 2026 to 2030 period. To a large extent this has already occurred in the annual revenue adjustments, but to the extent any non-expenditure of capex remains it will be accounted for in the k-factor adjustments during PR6.

4.7. Additions to the RAB

The regulatory treatment of additions to the TSO and TAO RABs is an important issue in a price review. This subsection explains the regulatory approach to the treatment of additions to the TSO and TAO RABs for:

- Interest During Construction (IDC); and
- Capital Contributions and Grants.

4.7.1. Interest During Construction

The CRU maintains the view that IDC should not be added to the respective RABs. This is due to the TSO and TAO receiving a return on the assets from the middle of the year in which the costs were incurred, rather than when the asset was commissioned. Depreciation is also provided as expenditure on assets incurred. This means that that the expenditure on assets still under construction during any given year will be included in the calculation of that year's annual depreciation. The CRU is maintaining this policy during the PR6 period, covering 2026 to 2030.

The CRU is also maintaining the policy that assets which have been added to the RAB, but have not been energised within five years (except in the case where the programme of work was scheduled to be longer than five years or where the TAO can satisfactorily show that the delay is

beyond its control) would be temporarily removed from the RAB (with all return and depreciation paused) until the point at which the asset can be energised and utilised. At this point, this does not result in any current reductions or removals from the TAO RAB.

4.7.1.1. Capital Contributions and Grants

In previous price reviews, capital contributions and grants were subtracted from capex in the relevant year. The CRU will continue applying this policy during the PR6 period, covering 2026 to 2030.

4.8. Working Capital Mechanism

ESB Networks have indicated that the scale of investment and global competition means that they are required to pre-purchase stock well in advance of assets being allocated to a specific project and, ultimately, becoming operational, or provide commitments for supply chain contracts. This leads to a financing cost for this pre-financing before recognition in the RAB, where it earns a return.

The Final Determination has introduced a new working capital ('side RAB') mechanism to reflect the cost of carry and impacts on finance raising of the growth of ESB Networks stock and supply chain commitments. The principles are equivalent to the EirGrid onshore TSO side RAB albeit for a different purpose and in a different regulatory framework. The mechanism directly targets the inherent financing challenges and business risks in procurement and supply chain management that ESB Networks reference. This mechanism was not in place for ESB Networks in PR5, thus its inclusion in PR6 is a material positive development in supporting business operations and reducing risk. The mechanism involves a nominal return on the cost of capital paid on the balance of working capital, formed using the real cost of capital used for the TAO and DSO businesses. The return will be applied to an NPV-neutral balance at a 5.66% nominal rate of return.

There is material uncertainty over the quantum of the values to be included in the regulatory determination. The opening value of current pre-financing has been provided by ESB Networks. Additions to stock or supply chain commitments will increase the balance, while additions to the RAB from stock or engagement of the supply chain will reduce the balance. The allowed revenues currently reflect the estimates provided by ESB Networks. However, the precise values will be subject to reconciliation on an annual basis, following CRU assessment of ESB Networks submissions. ESB Networks will provide this data as part of its annual submission process. The CRU will include values in the mechanism that it considers appropriate (including any split between transmission and distribution). The CRU assessment will also consider whether a

balance of start and closing balances appropriately reflects the effective cost of this pre-financing.

4.9. Conclusions

The CRU is not changing the RAB methodology relative to that employed during the 2021 to 2025 period.

As summarised above, the CRU considered ESB Networks' asset lives proposal and concluded that it will retain the PR5 approach to asset lives. Although as noted above, there has been changes made within the revenue modelling for PR6 to account for the issue regarding the allocation of secondary assets, for the purposes of depreciation, and the CRU confirms that it will work with ESB Networks to resolve the issue related to the implementation of the Replaced Assets policy.

5. Cost of Capital

The CRU, with the assistance of expert financial advisors, sets the fair rate of return that the regulated network companies can earn on the efficiently incurred capital investments in their RABs. This return is known as the WACC.

5.1. Introduction

The WACC is a weighted average of the cost of debt and the cost of equity[43]. It is the CRU's role to set a WACC that gives a fair deal to customers and the companies. If the CRU sets a rate of return that is too high, customers end up paying too much. If the CRU sets it too low, utilities cannot raise the finance to deliver the necessary level of network investment, which can result in a reduced quality of service for customers. Setting a fair rate of return helps the utilities manage their challenges, such as financing their investment programme.

Consistent with many other regulators in similar environments[44], when setting the appropriate cost of capital, the CRU has used a WACC methodology, estimating the cost of equity using the Capital Asset Pricing Model (CAPM) and the cost of debt using the data from capital markets. The CRU has used this methodology to set the cost of capital for the utilities it regulates including gas, water and electricity.

The CRU published an Information Paper in February 2020[45] setting out the principles for estimating the cost of capital across electricity, gas and water in Ireland. This paper noted that the CRU continues to review its methodology with the aim of ensuring it provides the best outcomes for customers.

The CRU has historically set the same cost of capital estimate for both the TSO and TAO, with a separate margin that reflects the TSO's asset-light characteristics (including high operational gearing). EirGrid's TSO function has a small RAB and setting the same WACC estimate thus had limited financial impact[46]. However, for the PR6 period, covering 2026-2030, there are grounds to

[43] For a notional company, not the true cost of debt and equity experienced by the companies
[44] This methodology is widely used by other Irish and European regulators in the electricity, gas, telecom and aviation industries.
[45] CRU20029 Cost of Capital CRU Approach
[46] WACC is multiplied by the RAB to estimate the allowed return to the network company. However, for EirGrid, a typical 'RAB x WACC' approach is not considered to provide sufficient remuneration due to its small RAB.

set separate WACCs for EirGrid (TSO) and ESB Networks (TAO/DSO), and thus consider the characteristics of the TSO directly in the cost of capital, in particular:

- EirGrid TSO's debt portfolio is different to that of the TAO – given the shorter asset lives of the TSO's asset base, the TSO uses a shorter-term debt than the TAO, with rates tied to (floating) EURIBOR, which impacts the benchmarks used.
- EirGrid TSO is relatively physically 'asset-light' in nature, and the systematic risks faced by the TSO may thereby differ from those faced by the TAO.

The CRU thus considers it appropriate for the EirGrid TSO WACC to reflect these characteristics rather than simply being assumed to be consistent with ESB Networks. In doing so, the separate margin that EirGrid previously received has been removed, with the operational gearing characteristics now reflected directly in the cost of capital.

This Final Determination Paper presents the results of the work that was completed when deriving the costs of capital for the TSO and TAO. A report provided by CEPA – Review of the Financial Regulatory Framework of the TSO for PR6 (CRU2025201) has been published alongside this paper and interested parties should refer to that document for further detailed information on these issues.

5.2. Methodology for Setting the Cost of Capital

The cost of capital value set out in this paper has been derived using an established CRU WACC methodology and approach, including using the CAPM for estimating the cost of equity, and as such this paper is restating the CRU's intention to continue using these methodologies to calculate the appropriate costs of capital for both the TSO and TAO for the 2026 to 2030 period.

Several key factors considered when estimating the cost of capital are set out below.

5.2.1. Key Considerations in Setting the WACC

The CRU considers a number of factors when setting the cost of capital. These have been reflected below, along with the rationale for PR6 cost of capital considerations.

Notional or Actual Capital Structure

The standard approach that the CRU has taken in previous price reviews (and in line with economic regulation in Ireland, UK and other European countries) is to set the allowed WACC with reference to a notional rather than actual capital structure for the regulated entities.

A notional capital structure ensures that the consumers only pay for efficient cost of capital. This means that any risks of financing decisions by the regulated companies, such as the level of gearing, timing of debt issuance, and choice of debt instrument, are ultimately borne by the shareholder and not the final customer. The consumer prices are thus set to ensure that a notionally efficient business would be financeable under the price control. At the same time, a notional capital structure incentivises the utility business to seek efficient low-cost financing.

The CRU has thus assumed a notional capital structure for the utility businesses for determining the cost of capital and carrying out financeability assessment[47] for PR6.

Tax treatment

Since the network companies are state-owned, it is assumed that the companies follow the headline corporation tax rate (12.5% in Ireland), rather than having a bespoke tax rate. The CRU has thus historically adjusted the post-tax WACC for headline corporation tax levels to derive the pre-tax WACC. Ireland signed up to the OECD pillar Two agreement in October 2021, including the agreement of a global minimum effective tax rate of 15% for firms that meet certain conditions. The Finance (No. 2) Act 2023 implemented the Pillar Two minimum effective tax rate in Ireland[48].

Following engagement with the network companies and our own analysis, we apply a 12.5% tax rate for ESB Networks and a 15.0% tax rate for EirGrid.

Real or Nominal WACC

A nominal rate of return includes inflation, whereas a real return excludes inflation. The RABs of ESB Networks and EirGrid are indexed to inflation, providing a return to the investors which compensates for inflation. The CRU thus sets a real WACC to ensure that the investors are compensated for inflation only once. The CRU purposes to continue with this approach for PR6.

Data used to estimate WACC

For PR5, we used Eurozone data rather than Irish-specific data. For PR6, we have continued with this approach, the rationale being that:

- the investors are more likely to view Irish regulated companies as part of an asset class that includes European utilities;

[47] See Section 6 on Financeability.
[48] See Guidance on Pillar Two available here.

- the European dataset is richer than the more limited Ireland-only data and is more likely to produce statistically robust estimates; and
- in a monetary union such as the Eurozone, individual countries would be expected to converge to a long-term equilibrium.

Aiming up

There are risks associated with setting a WACC which is too low or too high. Since WACC is the rate of return that can be earned on the RAB, setting a low WACC would lead to a reduction in investment levels and consequently a reduction in the service standards, thus resulting in long-term disadvantages to the customers, even though they might benefit from lower bills in the short run. On the other hand, over-funding can lead to investors receiving increased returns at the expense of customers. Setting too high a WACC, however, is considered to be less harmful as the increased return can create incentives to innovate and invest, which would ultimately benefit the customers in the long run.

The CRU and other regulators have historically adopted the view that the long-term consequences of under-estimation are worse and have thus set a WACC in excess of the level implied by the WACC formula. This increase is known as 'aiming up.' In PR4, PR5 and PC5, the CRU has aimed up to the 67th percentile. The CRU, however, does not mandate the use of the 67th percentile.

The CRU Cost of Capital Approach Information Paper (CRU20029)[49] states that:

"The CRU may also consider the context of the sector and any unique characteristics associated with the utility when coming to a decision on aiming-up. For example, the nature of the capital programme, the utility's funding model, and levels of uncertainty may be amongst the factors that the CRU takes into account when setting the aiming-up level for the WACC, if any."

- For PR6, the 67th percentile of the range is chosen, which is consistent with PR4, PR5 and PC5[50].

5.2.2. Building Blocks of WACC

The CRU sets the allowed rate of return as a WACC, weighting together debt and equity costs, using the following formula:

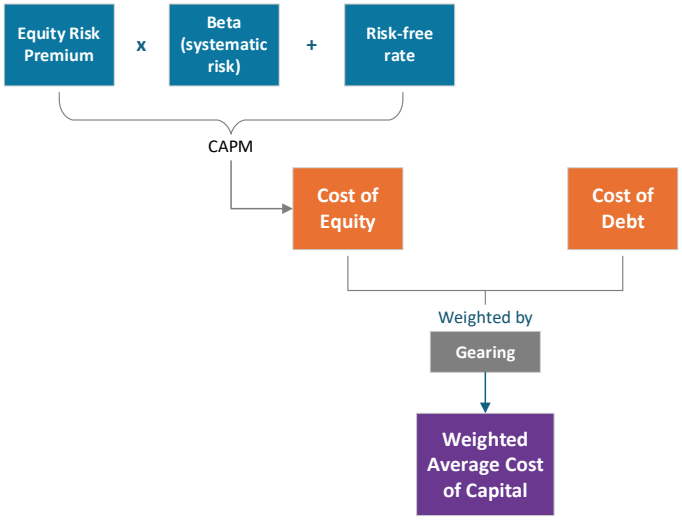
[49] CRU/20/029 – Cost of Capital – CRU Approach – Information Paper
[50] The 67th percentile for the TAO is 3.98%, which has been rounded to 4.00% for the decision.

$$WACC = \left(\frac{E}{D+E}\right) * CoE + \left(\frac{D}{D+E}\right) * CoD$$

- 'CoE' is the cost of equity;
- 'CoD' is the cost of debt;
- 'E' and 'D' are the total values of equity and debt respectively; and
- (D/(D+E)) represents notional gearing which is the proportion of debt that a regulated entity would hold.

Figure 6 below shows the different components that make up the cost of capital.

Figure 6: Building Blocks of Cost of Capital



The approach taken by the CRU along with the estimated value for each component of the rate of return is set out in the following sections.

5.3. Estimating the PR6 Cost of Capital

The CRU's expert advisors, CEPA, have assessed EirGrid and ESB Networks methodologies used in estimating the different components of the cost of capital.

The PR6 approach taken by CEPA to estimate these WACC components is set out in the below subsections. The CRU have adopted the CEPA recommendations for setting the cost of capital at PR6.

5.3.1. Cost of Equity

The CRU has historically used the CAPM to estimate the cost of equity. This approach is continued for PR6.

Risk-free Rate

In previous price controls, long-term German government bonds have been considered as a proxy for risk-free rate. CEPA recommend continuing with this established approach for PR6 for both the **TSO and the TAO**. German bonds are regarded as a good proxy for the risk-free rate of return on the Eurozone investments, as they are widely considered to have negligible default risk. CEPA focus on 1-month and 3-month trailing averages to inform their estimate.

CEPA have not adopted the forward curve adjustment suggested by ESB Networks in their response, nor the convenience yield adjustment, or higher yielding German 30yr bonds that EirGrid included.

Total Market Return (TMR)

For both the **TSO and the TAO**, CEPA focus on the historical *ex-post* and *ex-ante* evidence when estimating the TMR, utilising the Dimson, Marsh and Staunton (DMS) data series estimates (1900-2024) for Eurozone and other European countries. This parameter received limited feedback during consultation.

Asset Beta

As noted in Section 5.1, the CRU has previously used separate margins to reflect the asset-light characters of the **TSO**[51], including additional remuneration due to the risk associated with EirGrid's high operational gearing. However, with the separation of the WACCs for the TSO and the TAO for PR6, the CRU considers it appropriate to remunerate this through the WACC rather than through a separate margin, as it is the allowed WACC that compensates the shareholders for systematic risk. CEPA have thus included an uplift to the asset beta to account for the TSO's high operational gearing though the WACC.

[51] These margins target specific forms of return for the additional capital requirements of the TSO business, which relate to pre-construction (preliminary work in progress) activities, TUoS payments and collection, external payments and collection. See CEPA report on the Financial Regulatory Framework for the TSO (CRU202594) for further details.

For the **TSO**, CEPA estimate the asset beta uses regulatory precedent for other asset-light operators and triangulates against precedent in different context and empirical beta estimates. EirGrid had proposed an approach that utilised a 2015 CMA approach for estimating the asset beta of Bristol Water, but this proposal was not adopted by CEPA.

For the **TAO**, CEPA estimate the asset beta using a wider comparator set and a 'pure-play'[52] comparator set, placing more weight on the latter. 'Pure-play' energy comparators have greater similarity to the notional entity in terms of risk profile and thus are likely to provide a better evidence base for beta. CEPA place limited weight on more recent lower spot beta estimates in deriving their estimate. CEPA rejected ESB Networks' recommendation to remove REN as a comparator for estimating beta.

Debt and Equity Betas

CEPA recommend assuming zero debt beta for both the **TSO and the TAO**, consistent with the CRU regulatory precedent. The asset beta is then combined with the notional gearing to arrive at the equity beta.

Tax Rate

As noted above, CEPA use a 12.5% tax rate for the **TAO** and a 15.0% tax rate for the **TSO**.

5.3.2. Cost of Debt

At prior price reviews, the CRU has calculated notional debt rather than using the network companies' actual cost of debt to ensure that the consumers only pay for efficient debt costs. The same allowed cost of debt was allowed at prior price reviews for both the network companies, estimated using observed historical rates. However, for PR6, CEPA has recommended to use separate costs of debt for ESB Networks and EirGrid, since the efficient notional company for a network asset owner would be materially different than that for an asset-light company.

For both the **TAO and TSO**, the network companies had proposed using debt weights for individual years to reflect RAB growth that has varied in historical years, and will vary in future years. CEPA has reflected this in their recommendations on the cost of debt, leading to more weight being placed on later years of PR5 for embedded debt and more weight being placed on debt issued in PR6 given the significant increase in the investment programme, relative to the previous approach of a ten-year rolling average.

[52] Pure play comparators are companies with a substantial part of their business energy network related.

For the **TAO**, CEPA uses iBoxx EUR 10yr+ benchmark indices with broad A and BBB credit ratings. CEPA uses debt weights that reflect both RAB growth and refinancing.

For the **TSO**, the cost of debt estimation for PR6 involves a bond debt approach. CEPA put a greater focus on short-term debt (5-7 years). This is because the system operator has shorter asset lives which results in a greater proportion of shorter tenor debt reflecting in its debt profile. CEPA do not find sufficient robust evidence for including a small company premium. CEPA use debt weights that reflect RAB growth and refinancing.

5.3.3. Gearing

The CRU assumes a notional gearing level for the regulated companies, independent of their actual gearing. The CRU has consistently used a standard gearing level of 55%, in line with the levels assumed by other regulators in the UK and Europe.

Consistent with the network companies' proposals, and in line with the regulatory precedent, CEPA recommends a notional gearing assumption of 55% for both the **TSO and the TAO**. CEPA's financeability assessment shows that this level is appropriate within the context of PR6.

5.4. Conclusions

This section lists the cost of capital recommendations provided by CEPA to the CRU for the period 2026-2030 which reflects updated market data. It also lists the values of the factors that underpin this estimate. Both the TSO and TAO proposals are summarised in the CEPA report (CRU202594). These figures are also included in Table 33 and Table 34 below, along with the TSO's and TAO's proposed figures for comparison purposes.

5.4.1. TSO WACC Estimate

Table 33: Cost of Capital Estimates and Proposals - TSO

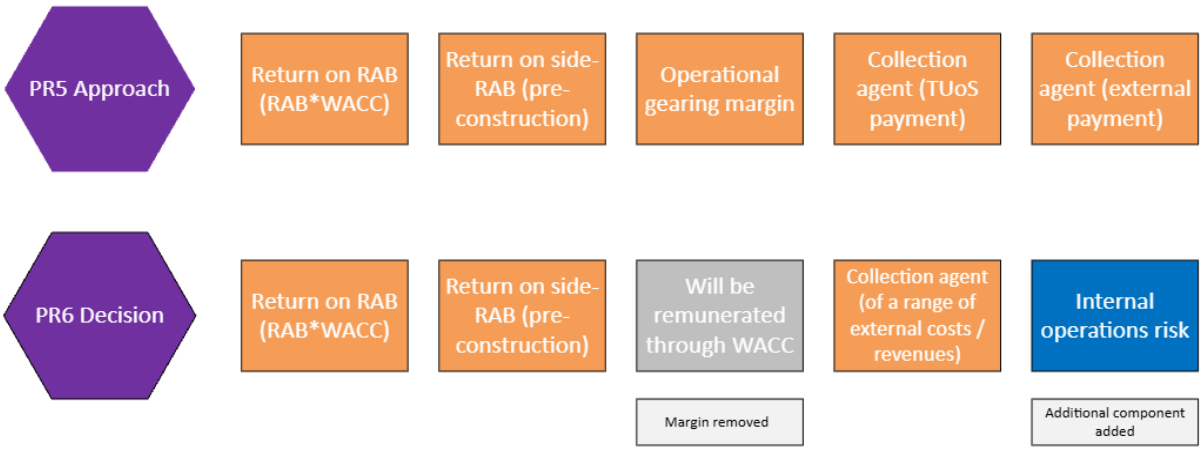
Parameter	CEPA PR6 DDs		CEPA PR6 FDs	
	Lower	Upper	Lower	Upper
Benchmark cost of debt	1.24%	1.43%	1.46%	1.46%
Issuance costs	0.10%	0.20%	0.10%	0.20%
Cost of debt	**1.34%**	**1.63%**	**1.56%**	**1.66%**
Risk-free rate	0.50%	0.75%	0.75%	0.75%
Total market return	6.40%	6.80%	6.40%	6.80%
EMRP	5.90%	6.20%	5.65%	6.05%
Asset beta	0.50	0.55	0.50	0.55
Equity beta	1.11	1.22	1.11	1.22
Cost of equity (post-tax)	7.06%	8.18%	7.03%	8.14%
Tax	12.5%	15.0%	15.0%	
Cost of equity (pre-tax)	**8.06%**	**9.62%**	**8.27%**	**9.58%**
Notional gearing			**55%**	
WACC (real, pre-tax)	**4.37%**	**5.23%**	**4.58%**	**5.22%**
Adjustment for inflation expectation	0.10%	0.40%	0.40%	
WACC (real, pre-tax) after adjustment for inflation expectations	**4.47%**	**5.63%**	**4.98%**	**5.62%**
Cost of Capital	**5.23%**		**5.41%**	

The following should be noted in conjunction with Table 33:

- The TSO (onshore) cost of capital has increased from 5.23% at Draft Determination to 5.41% for Final Determination.
- The increases are driven by:
    - The benchmark cost of debt increasing due to use of a weighted average and updated data.
    - A higher tax rate increasing the pre-tax cost of equity.
    - A larger inflation wedge.
- An increase in the risk-free rate leads to a slightly lower cost of equity for the TSO, as the equity beta is higher than one.

The CRU follows an approach that differs to a simple 'RAB x WACC' approach for the TSO to reflects its financial characteristics. Figure 7 shows PR5 TSO financial framework and the framework for PR6 for estimating the onshore TSO returns.

Figure 7: PR5 vs PR6 TSO Financial Framework



As noted previously, the risk associated with the TSO's high operational gearing will be remunerated through the WACC rather than a separate margin. In addition to the above, the TSO will be able to recover the commitment fees associated with their Working Capital Facilities (WCF).[53]

The margins have been informed by a total expected earnings before interest and taxes (EBIT) margin – the overall financial return achieved by the TSO. CEPA have conducted further analysis, informed by a submission from EirGrid and their consultants, on an appropriate return for the level of risk faced by the business across the different activities. CEPA propose a target EBIT margin range of 6-10%, with the proposed calibration leading to an 8.2% expected EBIT margin across PR6.

We note that the margin is based on a set of assumption, including the TSO RAB, incentive performance and the size of cashflows for which the TSO acts as collection agent for. We are not introducing any additional mechanisms to adjust the margin *ex-post*.

We note that the TSO onshore RAB value can be less stable than the TAO and DSO due to its shorter asset life and asset-light characteristics. This means that the individual margin components may need to be re-assessed at subsequent price controls to achieve an expected EBIT margin in the target range.

For PR6, CEPA has recommended increasing the margin on collection agent revenues to 0.375% (from 0.25%) and a margin on internal opex of 2.0% (from 1.0%).

[53] Changes to the size of the WCF are subject to CRU approval.

5.4.2. TAO WACC Estimate

Table 34: Cost of Capital Estimates and Proposals - TAO

Parameter	CEPA PR6 DDs		CEPA PR6 FDs	
	Lower	Upper	Lower	Upper
Benchmark cost of debt	1.18%	1.50%	1.49%	1.49%
Issuance costs	0.10%	0.20%	0.10%	0.20%
Cost of debt	**1.28%**	**1.70%**	**1.59%**	**1.69%**
Risk-free rate	0.50%	0.60%	0.75%	0.75%
Total market return	6.40%	6.80%	6.40%	6.80%
EMRP	5.90%	6.20%	5.65%	6.05%
Asset beta	0.31	0.35	0.31	0.35
Equity beta	0.69	0.78	0.69	0.78
Cost of equity (post-tax)	4.56%	5.42%	4.64%	5.46%
Tax	12.5%	15.0%	12.5%	
Cost of equity (pre-tax)	**5.22%**	**6.38%**	**5.31%**	**6.23%**
Notional gearing	55%			
WACC (real, pre-tax)	**3.05%**	**3.81%**	**3.26%**	**3.74%**
Adjustment for inflation expectation	0.10%	0.40%	0.40%	0.40%
WACC (real, pre-tax) after adjustment for inflation expectations	**3.15%**	**4.21%**	**3.66%**	**4.14%**
Cost of Capital	**3.85%**		**4.00%**	

The following should be noted in conjunction with Table 34:

- The pre-tax real WACC has increased from 3.85% at Draft Determination to 4.00% at Final Determination.
- The drivers of the WACC increase include:
    - Use of RAB weighting and updated data increasing the cost of debt.
    - A higher risk-free rate (from updated data) increasing the cost of equity (given that the equity beta is less than 1).
    - A higher inflation adjustment.
- The lower tax rate lowers the WACC.

5.4.3. Celtic Interconnector

In 2019 the National Regulatory Authorities, CRU in Ireland and CRE in France, published their coordinated Cross-Border Cost Allocation (CBCA) Decision supporting the Celtic Interconnector

project[54]. In 2022, the CRU published the Celtic CBCA decision paper[55] which provides detail on the CRU's cost recovery model for EirGrid. The CRU indicated its intention to set a separate allowed WACC for the Celtic Interconnector in this paper. The CRU has approved a fully regulated model for EirGrid's Celtic Interconnector (i.e. no merchant risk), structured into:

- **Phase 1 (pre-operational – development and construction):** EirGrid will only be allowed to recover eligible debt costs, and the efficiently incurred costs will be added to the RAB, determining its initial value for Phase 2. EirGrid will not earn any return on equity in this phase.

- **Phase 2 (operational):** the project will follow a RAB x WACC model, where Celtic will have a different RAB from EirGrid's other transmission activities. The CRU concluded that it would apply a nominal WACC specifically for the Celtic Interconnector, i.e., no RAB indexation, with the WACC set periodically alongside the price control decisions.

The CRU's PR6 WACC assessment for the Celtic Interconnector is 5.81% (nominal, pre-tax) for the Celtic Interconnector.

The CRU's advisors considered the below when determining the Celtic WACC. See the accompanying Price Review Six Onshore Cost of Capital report (CRU202594) for more detail on Celtic Interconnector WACC.

Cost of Equity

The risk-free rate and TMR parameters are economy-wide and therefore are applicable for the Celtic Interconnector for the cost of capital. Figures are converted into nominal terms using expected Eurozone inflation, consistent with the method used for deflating nominal figures initially[56].

The Celtic Interconnector asset beta had been set at Draft Determination at the 67th percentile of the asset beta range (i.e., 0.31-0.35) for the TAO and DSO businesses (i.e., the same point estimate as used for those businesses). For the Final Determination, the point estimate will be selected from the upper end of the range (i.e., 0.35). The estimate reflects an assessment of the full project investment cycle risk (including compensation for risks faced in construction and

[54] Revised Celtic CBCA Decision (CRU19125)
[55] Celtic Electricity Interconnector "EirGrid - Regulatory Framework Request" (CRU202213)
[56] An alternative approach would be to include the Irish-German inflation wedge and use forecast Irish inflation; however, the two approaches should be equivalent.

development). The higher asset beta reflects concentration risk for the Celtic Interconnector asset and a degree of uncertainty, but remains within the range used for the onshore networks.

Cost of Debt

EirGrid has a term loan of €600m in place, split from the European Investment Bank (EIB) and Danske, which will expire in September 2052. As debt has been issued, using a notional approach does not place any incentive on efficient debt issuance. However, there are challenges in terms of precedent from allowing actual debt costs.

Following a notional company cross-check undertaken by our advisers, actual (expected) debt costs will be used. This gives an allowance of 3.67% nominal. Fees are separately compensated. If project costs increase and more debt finance is required, the CRU will assess the efficiency of the higher investment costs first. If considered efficient, the allowed cost of debt will be re-assessed to reflect the weighted portfolio debt costs. A cross-check against a notional benchmark approach will also be undertaken to ensure that interest costs are also efficient and that consumers are not over-paying.

Gearing

A notional gearing level of 55% is provided, consistent with onshore gearing.

5.4.3.1. Celtic WACC Estimate

Table 35 below provides the estimated nominal pre-tax cost of capital for Celtic Interconnector.

Table 35: Cost of Capital Estimate - Celtic Interconnector

Parameter	CEPA Estimate
Nominal Cost of debt	**3.67%**
Real risk-free rate	0.75%
Real Total Market Return	6.67%
EMRP	5.92%
Asset beta	0.35
Equity beta	0.78
Real cost of equity (post-tax)	5.36%
Tax	15%
Real cost of equity (pre-tax)	**6.30%**
Assumed inflation	**2.0%**
Nominal cost of equity (pre-tax)	**8.43%**
Notional Gearing	55%
Nominal pre-tax WACC	**5.81%**

6. Financeability

The CRU is required to have regard to the ability of network companies to finance their operations[57]. The CRU has consistently interpreted this as to ensure that an efficient licence holder, in this case the TSO and TAO, are capable of financing their activities. The CRU has made some assumptions in this respect, which it considers are reasonable, noted below.

The TSO and TAO do not exceed the allowance for operating costs.

- The allowed operating costs are set at the level an efficient utility can achieve.

The effects of any unfinanced pension deficit are a matter for the network companies.

- The treatment of any pension deficits within both utilities will not be dealt with as part of the PR6 process.

The financeability assessment is based on the notional capital structure assumed by the CRU.

- It is not the function of the CRU to specify the capital structure of the TSO or the TAO, to the extent the actual differs from the notional any costs should be borne by the shareholder and not the final customer.

- If financeability assessment is based on an actual gearing level, achieving a certain credit rating might lead the utility business to raise its debt (gearing) levels, resulting in the regulator having to increase the cashflows (allowed return and depreciation) to ensure that the business can meet its debt obligations while remaining financeable.

6.1. Summary and Conclusions

The CRU's allowed Cost of Capital is based on the TAO achieving an investment grade credit rating with the licensee able to raise capital on reasonable terms. Our financeability analysis should be consistent with this. When looking at debt financeability, credit rating agencies take several factors into consideration in determining the rating of a company, such as quantitative metrics (like interest coverage ratios), as well as qualitative factors, such as the stability and predictability of the regulatory regime and the company's financial policy. The CRU understands that its regulatory framework is viewed as supportive by the rating agencies S&P and Moody's. Moody's specifically has noted the CRU's transparent, stable and predictable regulatory regime

[57] Electricity Regulation Act 1999, Section 9(4)(c). Available here.

based on clearly defined risk and reward principles, with the stability and predictability of the regulatory regime assigned a AAA rating in Moody's scorecard assessment.[58]

ESB Networks finance their network investments through the ESB Group and as such any assessment of the rating of ESB Networks as the TAO is notional. As context, Moody's August 2024 credit rating for ESB is A3 (Positive)[59]; which has recently been revised from a stable to positive outlook[60]. Similarly, S&P has recently upgraded ESB's credit rating to A with a positive outlook, and which took into account the CRU's PR6 Draft Determinations.[61]

EirGrid currently do not have a rating. However, over the PR6 period, EirGrid will seek a credit rating to support the significant funding that it would need to raise for its offshore activities. EirGrid anticipate that a credit rating might affect its financing approach for the onshore activities.

In carrying out financeability assessments for the regulated companies (in this case the TSO and TAO businesses and not the groups they are part of), the CRU does not consider it appropriate, nor is it in any case possible, to replicate all the factors that the credit rating agencies take into consideration when developing a credit rating. However, the rating agencies do publish their methodologies for rating regulated network utilities, and this gives guidance on what factors are taken into consideration, and the financial metrics associated with the different credit ratings.

The financial ratios consistent with Moody's Investment Grade Credit Rating on individual metrics are set out in Table 36 below.

[58] See Moody's Credit Opinion for ESB – June 2025 (p.13)
[59] ESB Credit Ratings – Moody's; Moody's A3 rating for ESB is maintained in its 2025 outlook on Regulated Electric & Gas Networks Europe (published on 10 April 2025), while the overall outlook for the sector has changed from stable to negative.
[60] The positive outlook reflects the positive outlook for the Government of Ireland, in light of the strong probability of major government support to ESB. Moody's ratings: here.
[61] ESB Credit Ratings – S&P: Ireland-Based Integrated Utility Electricity Supply Board Upgraded To 'A' On Government Support; Outlook Positive: here.

Table 36: Financial Ratios Consistent with an Investment Grade Credit Rating

Moody's[62]		
Metric	**A**	**Baa**
(FFO[63] + Interest)/Interest	4.0x – 5.5x	2.8x – 4.0x
FFO/Net Debt	18% - 26%	11% - 18%
AICR[64]	2.0x – 3.5x	1.4x – 2.0x
RCF[65]/Net Debt	14% - 21%	7% - 14%

S&P also produce guidance on quantitative factors that form part of their assessment, alongside qualitative factors. The ratios consistent with Investment Grade Credit Rating are set out in Table 37 below.

Table 37: Financial Ratios Consistent with an Investment Grade Credit Rating

S&P		
Metric	**A category ('significant' and 'intermediate' financial risk profiles)**	**BBB ('aggressive' financial risk profile)**
FFO / Cash Interest	2.0 to 5.0	1.5 to 2.0
FFO / Debt	9% to 23%	6% to 9%
Debt / EBITDA	3.0 to 5.0	5.0 to 6.0
EBITDA / Interest	2.5 to 7.0	1.5 to 2.5

The financial framework for the TSO differs, with a separate ratings methodology used for system operators.

As noted above, the CRU considers that the regulatory regime in Ireland is consistent with international best practice and provides a stable, predictable and transparent framework within which both the TSO and TAO operates, and which Moody's has assigned a AAA rating.

In terms of the financial profile, the CRU has assessed the TSO and TAO with regard to the financial ratios set out above and the relevant allowed cost of capital (5.41% for the TSO and 4.00% for the TAO). The TAO's relatively weaker financeability relative to the DSO reflects the large capex programme relative to the existing TAO RAB and the related pressure on the TAO cashflows. However, we consider the package financeable overall.

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[62] Moody's ratings, Regulated Electricity and Gas Networks, 2022, Exhibit 2 – available here.
[63] Funds From Operations
[64] Accrual-based Interest Coverage Ratio
[65] Retained Cash Flow

Our base case analysis for the TAO and combined ESB Networks business produces ratios that are broadly consistent with a comfortable investment grade credit rating (i.e. at least BBB+/Baa1) when including the 'base + AIMF' high spend case. The CRU understands this is the minimum credit rating level that ESB Networks consider is required for its PR6 programme to be financeable.

We also considered a range of plausible downside sensitivities and concluded that the notional company can maintain an investment grade credit rating (with our modelling indicating at least one notch headroom in plausible downside scenarios).

Notwithstanding the above, the CRU notes the unprecedented scale of the capital investment and financing programme that ESB Networks are expected to need to undertake over the PR6 period, and the inherent risks in the delivery of this scale of investment programme. Some specific financial ratios – e.g., the FFO / Net Debt ratio – are tighter in the high case scenario relative to the baseline, and there remain benefits for customers of the regulated company maintaining adequate cashflow and risk buffer in a scenario of accelerated infrastructure delivery and investment spend where this is facilitated by the PR6 AIMF.

As noted above, the CRU has a legal duty under the Act to have regard to the need to secure that licence holders are capable of financing their activities.

Consistent with its guidance in CRU202029[66], the focus of the CRU's financeability assessment is on the notional entity in order that the CRU can retain the incentive for the regulated utility to finance itself efficiently. However, in the event the actual company does not appear financeable, and the company can provide evidence that clearly demonstrates a real issue, the CRU will consider the effects and examine alternative approaches to achieve necessary cashflow levels, as real financeability issues for the company can lead to negative outcomes for customers.

For PR6, as part of monitoring the delivery of its capital programme, the CRU expects the network companies to monitor its delivery of the baseline and any accelerated AIMF spend and the impacts this accelerated delivery may have on its financial profile during PR6. Where the network companies can provide evidence that clearly demonstrates that it faces a financeability challenge in delivering any additional AIMF related spend above the baseline, it will be able to request that the CRU undertake a reassessment of financeability in the context of its revenue controls.

[66] CRU20029-Cost-of-Capital-CRU-Approach-Information-Paper.pdf

In reassessing financeability - and whether any intervention is required to improve the cashflow position of the licensee - the CRU will give regard to a range of indicators including:

- the published guidance of the rating agencies (e.g., S&P and Moody's) and the qualitative and quantitative factors (see above) in their guidance;
- the level of financial ratios for the licensee and/or the network companies (i.e. for ESB Networks, the combined business (TAO + DSO)) relative to the PR6 ex-ante baseline and high case; and
- that in delivering the additional AIMF spend, that the licensee's credit ratios will not be materially weaker than the ex-ante baseline, only to the extent that overall financeability represents a risk to programme delivery and/or consumer value.

Any reassessment of financeability will not give rise to an automatic financeability reopener or adjustment to allowed revenue. The CRU will continue to assess financeability based on an in-the-round assessment consistent with its approach for this PR6 Final Determination.

Temporary volatility, or outcomes that are a result of performance under its incentive framework, will not, of themselves, constitute grounds for review. In providing evidence that it will face a financeability challenge, the CRU will also expect network companies to consider factors which strengthen[67] as well as weaken its financeability position over the remaining period of PR6 where it is required to deliver additional AIMF related spend.

The text box below summarises the basis on which CRU would expect to undertake any financeability reassessment were it required to do so.

[67] For example, any future adjustment to revenues that the CRU may make for asset replacement.

Box 1 – Expected process of an in period financeability reassessment

Any reassessment of financeability will be based on an updated price control financial model for PR6 which should be submitted by the network companies to the CRU.

The CRU expects that the network companies would make such a request as part of its submissions into the PR6 annual reopener window. No in-period financeability adjustment will be made prior to the 2027/28 tariff year.

The reassessment will:

- be undertaken for the notional licensee (TAO and DSO) and at the CRU's assumption of notional level of gearing (55%);
- be undertaken based on the financial parameters allowed or assumed in the PR6 Final Determination and financeability assessment, i.e. allowed WACC and Cost of Debt;
- not take into account ESB Networks outturn performance under its performance incentive framework – i.e., it will assume a neutral scenario where there is no under or out performance of performance incentives; and
- consider the level of AICR and FFO / Net Debt (and other credit ratios as required) over the duration of the 5-year control – being the equivalent basis to the CRU's ex-ante financeability assessment – and the remaining period of PR6.

Where a financeability risk is identified, the CRU will respond in an agile and timely manner – i.e., the expectation is any intervention (see below) would be reflected in the next annual revenue and tariff decision following ESB Networks request for a review of financeability.

Should the CRU conclude that a financeability intervention is required to its revenue controls, it expects that this decision will likely need to be consulted upon.

Should the CRU determine that any intervention is required following a financeability reassessment, the CRU will explore the following interventions to address an identified revenue gap in the licensee's revenue control:

- increased revenue allowances;
- higher allowed WACC; and
- modifications to the depreciation profile.

Finally, the CRU notes that to deliver its PR6 investment programme, ESB Networks will need to access significant amounts of new debt and equity capital.

Illustrative CRU modelling for ESB Networks suggests an equity requirement may be required in the baseline (assuming 55% notional gearing and current ESB dividend policy) which would increase under the high expenditure case.

The CRU notes the recent announcement by the Government to allocate new investment (€1.5bn) into the delivery of distribution networks and the support that this provides to the financing of the programme by the regulated company. This support from Government is also referenced within S&P's recent rating assessment of the ESB Group, as of September 2025.

7. Allowed Revenues

The subsections below set out the allowed revenues for the TSO and TAO, as determined within the CRU's revenue model.

7.1. Revenue and Profiling

The PR6 price profile is defined as the profile of revenues the CRU sets at its Final Determination, which will be influenced by choices on how the CRU chooses to sculpt and smooth (or not smooth) its allowed revenues at PR6. As detailed in this Final Determination, there will be a significant increase in allowed revenues for the network companies for the PR6 period, which has implications for the PR6 price profile.

The CRU must balance a number of criteria when assessing and defining the price profile for PR6. These are summarised below:

- **Legitimacy:** The price profile achieves an appropriate balance of distributional and intergenerational equity between consumer groups. The proposals are proportionate.
- **Financeability:** The price profile enables the price control to be financeable, for example, in potentially facilitating the notional efficient company achieving key credit metrics.
- **Cost reflectivity:** Overlapping with legitimacy, the price profile ensures that users of the network are making a proportionate contribution to its costs given the objectives for PR6.
- **Practicality and simplicity:** As far as possible, the approach to determining the price profile should be targeted and as transparent and simple as possible.
- **Predictability and volatility**: The price profile for PR6 should deliver stable and predictable tariffs as far as possible, and avoid undue volatility of bills.

Taking the above into account, the CRU's approach for PR6 is to set a baseline revenue allowance that reflects CRU's view of core efficient opex and capital maintenance and an initial *ex-ante* allowance for enhancement related expenditure, with the network companies having the ability to access significant additional revenues through the AIMF where clear milestones or triggers are met. The level of agile revenues seeks to balance the predictability of the price profile with legitimacy, while enabling a financeable price control.

The allowed revenues for the TSO and TAO are set out in Table 38 and Table 39 below, respectively.

Table 38: PR6 Allowed Revenues for the TSO

2024 prices (€m)	2026	2027	2028	2029	2030
Internal opex	155	174	178	179	181
External opex	609	253	114	53	30
TAO revenues	354	394	426	466	518
FASS	-	371	382	404	413
Depreciation	52	74	94	102	97
Return on Stage 1 Working Capital	2	2	1	1	1
Return on other working capital	8	9	8	8	9
Return on fixed assets in the RAB	11	14	16	15	13
Incentives	-	-	-	-	-
PR5 adjustment	-	-	-	-	-
Working Capital Facility Fees	1	1	1	1	1
Adjustment to fix Y1 to Draft Decision value	-19	5	5	6	6
Revenue Requirement	1172	1297	1224	1234	1266

Table 39: PR6 Allowed Revenues for the TAO

2024 prices (€m)	2026	2027	2028	2029	2030
Opex	83	84	82	82	89
Depreciation	126	138	153	171	190
Return	153	166	184	207	231
Incentives	-	-	-	-	-
PR5 adjustments	-7	-7	-7	-7	-7
Adjustment to fix Y1 to Draft Decision value	-11	3	3	3	3
Revenue Requirement	344	383	416	455	508

Appendix 1 – PR6 Transmission Capex

TSO/TAO Network Capex Final Determination

Table 40: TSO/TAO PR6 Network Capex Final Determination - Baseline

TSO	2026	2027	2028	2029	2030	FD Total €m
Network Capital Expenditure	**54.8**	**60.7**	**40.0**	**57.0**	**34.9**	**247.4**
TSO Transformation	15.6	15.5	16.5	7.1	7.0	61.7
Technology Resilience and Modernisation	17.3	28.8	20.3	15.3	12.3	94.0
Power System Capability Enhancement	7.7	15.2	15.8	14.0	12.9	65.6
Digital Transformation	9.9	12.7	8.0	5.0	3.6	39.2
Celtic Operational Readiness	16.8	12.1	-	-	-	28.9
Physical Control Centres	7.9	15.4	0.1	-	-	23.4
Cyber Security	4.5	2.6	1.8	1.8	2.6	13.3
TSO/DSO Coordination	2.0	2.2	2.3	1.1	1.0	8.7
Workplace/Facilities Capex	0.6	0.6	1.3	1.6	1.2	5.4
Capability Catch Up	0.5	0.5	0.4	0.4	0.4	2.2
FASS	18.1	0.1	-	-	-	18.2
SMP	32.9	20.6	30.6	5.2	-	89.3
Market System Release Capital	0.9	4.4	4.4	4.8	5.1	19.6
Non-Network Capital Expenditure Total	**134.8**	**130.7**	**101.6**	**56.3**	**46.1**	**469.5**
Overall PR6 Total Capital Expenditure	**189.6**	**191.4**	**141.6**	**113.3**	**81.0**	**716.9**
TAO	**2026**	**2027**	**2028**	**2029**	**2030**	**FD Total €m**
Group 1 – Priority Projects	224.5	331.8	421.1	491.1	544.0	2,012.5
Group 2 – Remaining Category 1 Projects	14.5	29.0	33.1	35.9	40.0	152.5
Group 3 – Category 2, 4 and remaining Category 5 projects	88.0	119.6	136.7	148.1	165.1	657.5
Group 4 – Remaining Category 3 projects	-	16.3	18.1	16.5	16.0	66.9
Group 5 – Category 6, 7 and 8 projects	0.2	25.2	28.8	31.2	34.7	120.1
TAO Network Subtotal	**327.2**	**521.9**	**637.8**	**722.8**	**799.8**	**3,009.5**
Distribution Asset Management	-	-	-	-	-	0.0
Enterprise Applications	1.3	1.3	1.3	1.3	1.3	6.5
TAO Non-Network Subtotal	**1.3**	**1.3**	**1.3**	**1.3**	**1.3**	**6.5**
Customer Contributions	-28.0	-28.0	-28.0	-28.0	-28.0	-140.0
Interest During Construction	-	-	-	-	-	-
TAO Net Forecast Expenditure	**300.5**	**495.2**	**611.1**	**696.1**	**773.1**	**2,876.0**
Overall PR6 Total Capital Expenditure	**490.1**	**686.6**	**752.7**	**809.4**	**854.1**	**3,592.9**

TSO PR6 Non-Network Capex

Table 41: TSO PR6 Non-Network Capex Request vs. Allowance

Category	TSO Request (€m)	FD Baseline (€m)	FD High (€m)
TSO Transformation	133.7	61.7	112.7
Technology Resilience and Modernisation	100.9	94.0	101.0
Power System Capability Enhancement	90.2	65.6	90.2
Digital Transformation	49.2	39.2	49.2
Celtic Operational Readiness	32.0	28.9	32.0
Physical Control Centres	23.4	23.4	23.4
Cyber Security	13.3	13.3	13.3
TSO/DSO Coordination	11.1	8.7	11.2
Workplace/Facilities Capex	5.3	5.4	5.4
Capability Catch Up	4.1	2.2	4.1
FASS	18.2	18.2	18.2
SMP	89.3	89.3	89.3
Market System Release Capital	19.6	19.6	19.6
Total for PR6	**590.3**	**469.5**	**569.6**

Appendix 2 – PR6 Transmission Opex

Table 42: TSO/TAO PR6 Network Opex Final Determination - Baseline

TSO	2026	2027	2028	2029	2030	FD Total €m
Staff costs	68.6	76.1	78.6	79.4	79.6	382.3
Staff related costs	3.8	4.2	4.4	4.4	4.4	21.2
Contractors	19.2	19.7	19.6	19.1	19.0	96.6
Telecommunications	7.4	7.9	8.0	8.0	8.1	39.4
Premises	8.1	8.5	8.5	8.4	8.4	41.9
IT Costs	20.1	28.7	29.3	28.3	28.4	134.8
Insurance	0.9	0.9	0.9	0.9	0.9	4.5
Public Engagement	2.3	2.3	2.3	2.3	2.3	11.5
Professional Services	22.0	21.7	20.4	20.5	20.6	105.2
Grid Maintenance & Client Engineering	1.1	1.1	1.1	1.1	1.1	5.5
Rates	0.6	0.6	0.6	0.6	0.6	3.0
Promotion of Research	1.4	1.4	1.5	1.5	1.5	7.3
Intercompany Recharges	-3.2	-3.2	-3.2	-3.2	-3.2	-15.9
Total Controllable (Incl. Frontier Shift)	**154.9**	**174.3**	**178.0**	**178.8**	**180.7**	**866.9**
Total Controllable (Excl. Frontier Shift)	**152.3**	**169.9**	**172.0**	**171.3**	**171.7**	**837.4**
Inter TSO Compensation	3.7	3.7	3.7	3.7	3.7	18.5
CORESO subscription	1.3	1.3	1.3	1.3	1.3	6.5
Interconnector services	1.0	1.0	1.0	1.0	1.0	5.0
CRU Levy	3.0	3.0	3.0	3.0	3.0	15.0
DUoS costs	6.9	6.9	6.9	6.9	6.9	34.5
Ancillary Services	280.7	1.5	1.5	1.5	1.5	286.7
Future Arrangements for System Services	-	370.5	381.8	403.5	412.5	1,568.3
Total Non-Controllable	**296.6**	**387.9**	**399.2**	**420.9**	**429.9**	**1,934.5**
Security of Supply	274.0	219.0	83.9	23.2	-	600.1
Celtic Debt Service Costs	25.0	4.7	-	-	-	29.7
FASS funding costs	2.0	0.9	0.9	0.9	0.9	5.6
Clean Energy Package	22.0	22.0	22.0	22.0	22.0	110.0

Total Exceptional Items	**323.0**	**246.6**	**106.8**	**46.1**	**22.9**	**745.4**
Total Opex (Incl. Frontier Shift)	**774.5**	**808.8**	**684.0**	**645.8**	**633.5**	**3,546.8**
Total Opex (Excl. Frontier Shift)	**771.9**	**804.4**	**678.0**	**638.3**	**624.5**	**3,517.3**
TAO	**2026**	**2027**	**2028**	**2029**	**2030**	**FD Total €m**
Transmission Operations	3.6	3.8	4.1	4.5	4.9	20.9
Planned Maintenance	23.8	23.3	22.7	22.6	23.0	115.4
Fault Maintenance	2.3	2.3	2.4	2.4	2.4	11.9
Transmission Retirements	-	-	-	-	-	-
Asset Management	0.9	0.9	1.0	1.0	1.0	4.8
Company Wide Costs	0.4	0.4	0.4	0.4	0.4	2.1
Corporate Charges	3.6	3.6	3.6	3.5	3.5	17.9
Insurance	0.3	0.3	0.3	0.3	0.3	1.5
Legal	-	-	-	-	-	-
Pension	0.2	0.2	0.2	0.2	0.2	1.0
IT Opex	0.5	0.5	0.5	0.5	0.5	2.5
Miscellaneous	-	-	-	-	-	-
Professional Fees	2.9	2.9	2.9	2.9	2.9	14.5
Telecom Fees	2.2	2.2	2.2	2.2	2.2	11.0
Total Controllable (Incl. Frontier Shift)	**40.8**	**40.6**	**40.6**	**40.8**	**41.7**	**204.5**
Total Controllable (Excl. Frontier Shift)	**40.7**	**40.4**	**40.3**	**40.5**	**41.3**	**203.2**
Network Rates	38.6	39.7	38.2	37.5	44.4	198.3
CRU Levy	3.3	3.3	3.3	3.3	3.3	16.7
Total Non-Controllable	**41.9**	**43.0**	**41.5**	**40.8**	**47.7**	**215.0**
Total Opex (Incl. Frontier Shift)	**82.8**	**83.6**	**82.2**	**81.6**	**89.4**	**419.5**
Total Opex (Excl. Frontier Shift)	**82.7**	**83.4**	**81.9**	**81.3**	**89.0**	**418.2**

Appendix 3 – Valuation of the Regulatory Asset Base

The core issue regarding the valuation of the TSO's and TAO's RAB is whether the RAB should reflect the value of the assets now (replacement value) or when they were built (acquisition cost). A number of variations on these approaches are outlines below. The advantages and disadvantages of each were set out in PR5 and still hold true.

Acquisition Cost

Assets are valued at their original cost for construction/acquisition. The value of the assets is not indexed for inflation nor is the value linked to the cost of replacement.

Replacement Cost

Assets are valued at what it would cost to replace existing assets. There are two approaches to replacement cost: (a) indexing the acquisition cost of the asset to allow for inflation; and (b) revaluing the asset base using a modern equivalent asset value (MEAV) approach.

Replacement cost less stranded assets

This is as per replacement cost above but those assets that are not utilised in the current system would be excluded. Effectively, this would be the cost of building a replacement system.

Deprival value

The assets would be valued at the lower of their replacement cost or economic value (in the event that they could not be replaced).

The CRU has decided that the TSO and TAO's RABs will continue to be valued using a replacement cost approach for the period 2026-2030. This aligns with the approach taken in the previous price reviews and provides significant regulatory stability.

Asset Lives Applied to the Regulated Asset Base

The decision on asset lives that applies to assets within the RAB feeds through to the level of depreciation that the TSO and TAO receive separately on those assets within each price review (or indeed year).

In line with established practice, the CRU is continuing to use average assets lives as determined in PR5. PR5 reviewed the appropriateness of the asset lives, taking account of the economic and technical lives of the assets on the TSO and TAO RABs.

There is one exception to this. For PR5, the CRU Final Determination Revenue paper set out a Secondary Asset life of 10 years for the TAO, however, in the TAO revenue model, this was set to 17 years. For PR6 we have aligned the revenue model to include a secondary asset life of 10 years.

These asset lives are set out in Table 43 and Table 44 below.

Table 43: Asset Lives for PR6 - TAO

Asset	PR6 (yrs.)
Network Assets	50
Telecoms	50
Office Equipment	10
SCADA Telecoms	15
Premises	50
IT	5
Customer Contributions	50
Secondary Assets	10

Table 44: Asset Lives for PR6 - TSO

Asset	PR6 (yrs.)
IT	5
Overheads	10
Premises	23
Communications	10
Telecoms	10
Enterprise Applications	5
Customer Contributions	15